STUDY ON PETROLEUM FUEL DESULFURIZATION
IN THE PETROLEUM INDUSTRY

(VOLUME 1 OF 2)

FOR

ENVIRONMENT CANADA

DSS FILE 53SS.KE145-2-0734

MHG International Ltd.
Project No. FED-0256
Toronto

August 1983

STUDY ON PETROLEUM FUEL DESULFURIZATION IN THE PETROLEUM INDUSTRY (VOLUMES 1 AND 2)

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STUDY ON PETROLEUM FUEL DESULFURIZATION IN THE PETROLEUM INDUSTRY

(VOLUME 1 OF 2)

FOR

ENVIRONMENT CANADA

DSS FILE 53SS.KE145-2-0734

MHG International Ltd.
Project No. FED-0266
Toronto

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SUMMARY

The effect of reducing the sulfur contents of the various grades of fuel oil products was investigated. The sulfur was reduced by increasing the hydro-desulfurization process throughput, and the addition of H-Oil process to hydrocrack the vacuum resid. Different scenarios were simulated for the four regions in Canada with MHG refinery computer model based on 1981 operation. Each region is represented by a composite refinery.

The simulation results covering annual sulfur reductions, changes in crude requirements and product rates, additional process unit capacities required, increases in annual operating costs and capital investments required for different levels of desulfurization in fuel oil products are presented.

To achieve 0.3 wt% sulfur in LFO and lighter products, which represents a sulfur reduction of 6,200 tonnes/year as compared to the 1981 operation, though increased operating cost of 1¢/Bbl crude feed is estimated, no investment is required. To achieve 0.1 wt% sulfur in LFO and lighter products, which represent 43,800 tonnes/year sulfur reduction as compared to the 1981 operation, increase in operating cost is estimated at 7¢/Bbl crude feed and investment at 52.4 million dollars.

To achieve 0.3 wt% sulfur in LFO and lighter products and to minimize the crude requirement by hydrocracking the vacuum resid with low conversion H-Oil process, investment required is 1.72 billion dollars for Canada as a whole, mostly for H-Oil facilities. Sulfur reduction in fuel oil products increases to 268,600 tonnes/year mainly due to substantial reduction in HFO production and equivalent reduction in crude oil requirement of 82.3 million barrels/year (or 12.5%).

To achieve 0.1 wt% sulfur in LFO and lighter products using the same strategy, investment of 1.78% billion dollars is required, mainly for the H-Oil facilities. The corresponding sulfur reduction in fuel oil products is 306,300 tonnes/year resulting from the reduction of HFO production. The reduction in crude requirement is the same as the previous case.

Further reduction in sulfur in fuel oil products, crude requirements and HFO productions can be achieved with the high conversion H-Oil process, which requires higher investment.

RESUMÉ

RESUMÉ

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1.0 INTRODUCTION

The refineries in Canada in 1981 processed approximately 640 million barrels per day of crude into various grades of petroleum products. Some of the sulfur in the crude oil was removed by desulfurization processes and recovered as elemental sulfur. The sulfur which remained with the products was emitted to the atmosphere as sulfur dioxide when the products went through the combustion process. As an objective, an ongoing effort is made by Environment Canada to regulate the sulfur dioxide emitting to the atmosphere. To assist in these efforts, the Air Pollution Control Directorate of Environment Canada commissioned MHG International Ltd. to study the effect on the refining industry of reducing the sulfur content of fuel oils to various levels, and to provide estimates of the increased operating and capital investment costs related to achieving these objectives.

A similar study (5) was carried out by MHG International Ltd. for Environment Canada in 1981 under DSS File 37SS.KE 204-0-0516 based on the industry's 1979 operation as a reference case. This study utilized a computer model developed by MHG and based on a composite refinery concept, similar to that used on the previous study. The reference base case is to be updated for the 1981 operation. In addition to the desulfurization objective, crude oil is to be reduced by hydrocracking the vacuum resid to reduce the production of heavy fuel oil. This will provide some indication on the viability of replacing the heavy fuel oil with alternative fuels which are more available within Canada or which are cleaner.

2.0 SCOPE OF STUDY

The scope of work to be executed is defined in detail in appendices as received in the inquiry letter from the Department of Supply and Services and subsequently updated in the proposal submitted by MHG International Ltd. according to the discussion with Environment Canada.

The work to be undertaken is to evaluate the effect upon refinery operations of reducing the sulfur contents of the various grades of fuel oils produced by increasing the hydro-desulfurization process throughput, and the addition of H-Oil process to hydrocrack the vacuum resid.

The study will use the 1981 operation as the base case and will encompass all of the refineries that were operating in that year. Since individual refinery operating data are not available, the study will examine the effect on a regional basis and on Canada as a whole. The same strategy used in the previous studies will be adopted to divide the country into four regions namely Atlantic, Quebec, Ontario and Western regions based on the predominant crude oil diet. Individual refineries within each region will be allocated their share of additional capacity based on their own particular crude oil feed capacity and process configuration.

2.1 Cases to be Studied

The following six cases will be investigated:-

Case 1 No. 2 light fuel oils and lighter will be restricted to a sulfur content of 0.3 wt.% or to the sulfur content of the base case for certain grades of light fuel oil, whichever is lower. Fuel oils heavier than No. 2 fuel oil will be limited to the same sulfur content as the base case.

Case 2 Same as Case 1 above except that light fuel oil (LFO) products restricted to 0.1 wt.% sulfur.

Case 3 This case will assume an H-Oil unit to treat the vacuum column bottom stream. A low conversion of approximately 66 v% will be assumed (conversion being defined as the v% of the feed material boiling above 975°F converted into lighter products). At the same time, the light fuel oil products will be limited to the same restriction in sulfur content as Case 1 i.e. maximum of 0.3 wt.% sulfur or the sulfur content of the base case whichever is lower. Fuel oil heavier than the No. 2 fuel oil will be limited to the same sulfur content as the base case if practical.

Case 4 Same as Case 3 except that light fuel oil products limited to 0.1 wt.% sulfur.

Case 5 Same as Case 3 except that 90 v% conversion H-Oil units will be used.

Case 6 Same as Case 4 except that 90 v% conversion H-Oil units will be used.

2.2 Computer Simulation

The mass balance and property evaulation will be done on the MHG refinery simulation model previously developed. The program will be modified to include the H-Oil unit for handling the vacuum resid.

2.3 Basis for Product Slates and Product Objectives

The product slate in general will be consistent with the base case which is the 1981 operation for comparison purposes. Fuel gas product will be floating to satisfy the mass balance. The prime objective of incorporating the H-Oil unit is to convert the vacuum resid to lighter products, which results in reducing the production of heavy fuel oils and the requirement of crude oils. As the H-Oil is a hydrocracking process, significant desulfurization of the liquid is also accomplished though this is not the prime objective. For cases 3 to 6 in which H-Oil units are included, the study will duplicate only the product output for No. 2 fuel oil and lighter liquid products. The heavier products will be kept within the quality specification. The production rate and sulfur content of the heavy fuel oil will be determined by the process consideration to meet the vacuum resid conversion objective.

2.4 Presentation of Study Results

The study will present the following results for each of the six cases and for each of the four regions and for Canada as a whole.

1. Annual sulfur reduction caused by changes in fuel oil sulfur specification, broken down into own fuel consumption, saleable heavy fuel oil and saleable light fuel oils.

2. Investment on new facilities: This will be determined by firstly assessing the additional capacities required in each region. Each refinery in the region will then be allocated a proportion of new facilities in relation to its crude unit capacity, taking into account the existing installed unit capacity. This approach may result in capacities of some new units which are too small to be practical. In these cases, the smallest practical size unit will be assumed for cost estimating purposes.

3. Revised crude oil requirements.

4. Increased annual energy and utilities requirements.

5. Increased requirements of operating materials such as catalysts and chemicals.

6. Increase in annual operating costs from:-
   - Capital charge at 25% on capital investment.
   - Crude oil cost based on \$34/bbl for all regions for 1981, and other crude oil costs of \$30/bbl, \$35/bbl, and \$40/bbl.
   - Changes in product rates such as fuel gas and sulfur. Changes in heavy fuel oil production will be expressed in flowrates and in quantities of coal or natural gas with equivalent energy. Changes in vacuum resid will be expressed in flow rate only. The costs related to changes in these two products will not be included in the operating costs.
   - Additional energy requirement by process units and operating materials.
   - Fixed Annual Operating Cost
     - Salary for operating personnel including supervisory/ technical personnel;
     - Maintenance will be based on 3% of capital investment cost;
     - General, sales, administration, taxes and insurance will be based on 3.5% of capital investment;
     - Basis for operating cost calculation will be:-

       Annual on Stream Time - 325 days per year

       Fuel oil heating value - 6.3 million/Bbl

       Electricity - 1 kWh = 10,000 BTU

       Steam - 1 lb. = 1,000 BTU

7. Capital and Operating cost estimates will be based on mid-1982 costs.

3.0 METHODOLOGY

For this study, Canada was divided into four regions, namely Atlantic, Quebec, Ontario and Western which have their distinct crude diet used by refineries as stated in Scope. Figure 3.0.1 defines these regions graphically. Each region is represented by a composite refinery. The capacity of each process unit in each of the four composite refineries was taken to be equal to the sum of the installed capacities of all the units in operation in 1981 within that region. This information is provided in Section 3.5.3. Simulations of the operation of the composite refineries were done on a computer model which has recently been modified to suit the requirements of this study. In addition to the modification on the computer model, a new program was added to perform mass balance refinement and utility data handling. The print-outs are divided into Part I for the computer model program and Part II for the mass balance refinement and utility data handling program.

3.1 Computer Model

The computer model was developed to reflect the general refinery process unit configuration shown in Figure 3.1.1. A similar simulation model was used in the earlier studies (4, 5). The computer model performs material balance and property calculations. It includes the following major refinery processes: crude/vacuum distillation, catalytic reforming, catalytic cracking, isomerization, alkylation, polymerization, gas recovery and hydrotreating. H-Oil unit for handling the vacuum resid has been recently added for the use of this study. No economic data was incorporated into the program but reliance was placed on user interaction to develop an optimum solution. A brief description of the process units within the model is summarized below:

a) Crude/Vacuum Distillation

These units provide the following cuts which normal ranges of TBP end points are indicated.

	TBP End Point
Crude Tower Overhead/LSR	140 - 210°F
Naphtha	300 - 400°F
Kerosene	480 - 550°F
Light Gas Oil	600 - 700°F
Heavy Vacuum Gas Oil	900 - 1050°F
Vacuum Resid	-

The end points are allowed to vary within the ranges to meet the product specs. and product slates. For example, a lower contribution to the gasoline pool of the light straight run gasoline (LSR) which has low octane rating will result with a lower LSR end point. All end points can be defined by the users except those for light straight run and naphtha cut which are determined by the product rate and reformer throughput specified by the users.

b) Catalytic Reforming

The process unit is based on semi-regenerative type and monometallic platinum catalyst. Product yield is a function of severity which is expressed in reformate octane quality and feed characterisation factor. The feed is hydrotreated.

c) Catalytic Cracking

An FCC unit using zeolite catalyst and a blend of light gas oil and heavy vacuum gas oil feed stock is assumed for the catalytic cracking unit. Product yield and quality are predicted as a function of gravity of feed and severity (conversion level).

d) Isomerization

Light straight run gasoline (LSR) (C_5 - C_6) feedstock with no recycle is assumed.

e) Alkylation

It is based on HF alkylation process. Iso-butane requirement is taken to be 1.24 volumes per volume of olefin from the catalytic cracking unit and it is assumed iso-butane can be imported as required to react with all olefins allocated to alkylation.

f) Polymerization

It polymerizes the olefins from the catalytic cracking unit allocated to this unit to produce gasoline boiling range product.

Process yield correlation for the above catalytic processes was developed from in-house data and those published in literatures.

g) Gas Recovery

The model assumes that the gas plant has the capability to recover practically all iso-butanes for alkylation and 100% of C_4's for blending as required from all sources (crude tower overhead, catalytic reforming, catalytic cracking, polymerization and alkylation units). The remaining C_4's and lighters are assumed to be taken as refinery fuel gas.

h) Hydrotreating

The hydrotreaters as represented in the computer model (Print-out Part I) only remove sulfur. All feed is assumed to be recovered as desulfurized product with no generation of naphtha or light ends. All the product properties except sulfur content are assumed to be the same as those of the feed. Sulfur removal efficiency is assumed to be 100% for naphtha/LSR, 95% for kerosene and 90% for light gas oil (LGO), light cycle oil (LCO) and H-Oil light gas oil (HO-LO), and 85% for heavy cycle oil (HCO). The comments on hydrotreater mass balance should be noted when reading the print-out of the computer model (Part I).

The product yields of the hydrotreaters calculated in the computer model and described above are subsequently adjusted in the mass balance refinement and utility data handling program (Print-out Part II). The basis of yield adjustment is provided in Section 3.5.4.

i) Supporting Process Units

The supporting process units such as hydrogen plant, sulfur plant, amine plant and sour water stripping facilities are not represented in the computer model. Calculation of the required throughput of these units are done in the mass balance refinement and utility data handling program which will be described later. Relation of these units to the main process units are summarized below and illustrated in Figure 3.1.2.

j) Amine Plant

The feed to the amine plant is the sour gas from H-Oil unit, hydrotreaters and refinery sour fuel gas. All the H_2S in the feed is removed from the feed and sent to the sulfur plant.

k) Sulfur Plant

For mass balance purposes, it is assumed that all the sulfur in the feed is separated and converted to elemental sulfur. For sulfur plant cost estimate, either 97% or 99^+% sulfur recovery was used, depending on size of the process unit.

l) Hydrogen Plant

All the hydrogen from reformer is assumed to be available to users such as hydrotreaters and H-Oil units. If the hydrogen demand exceeds the available supply, then a new hydrogen plant is required.

The feed to this plant is either imported natural gas or naphtha produced in the hydrotreaters and if that is not sufficient then imported naphtha is used to make-up the total naphtha demand for hydrogen plant.

m) Sour Water

Rate of sour water produced in hydrotreaters are calculated using the basis provided in Section 3.5.4 and the following estimate:

Amine Plant producing 0.9 lb of sour water per lb of H_2S and H-Oil unit producing 0.12 lb of sour water per lb of feed.

n) Other Processes

There is no hydrocracking unit in the model. In this study, hydrocracking unit was simulated with the catalytic cracking unit model assuming same product yield and quality. The approximation is more severe in the Atlantic region where hydrocracking constituted about 39% of the total cracking capacity. In the other regions, the proportion of hydrocracking capacity was substantially smaller. For the objective of this study, this approximation will result with a conservative estimate on the requirement of hydrotreating. The processes for production of coke, asphalt and lube oil are not represented in this model. However, in order to account for these relatively small products, certain allocations depending on the cases being studied, were taken from various streams as depicted in the block flow diagram Figure 3.1.1.

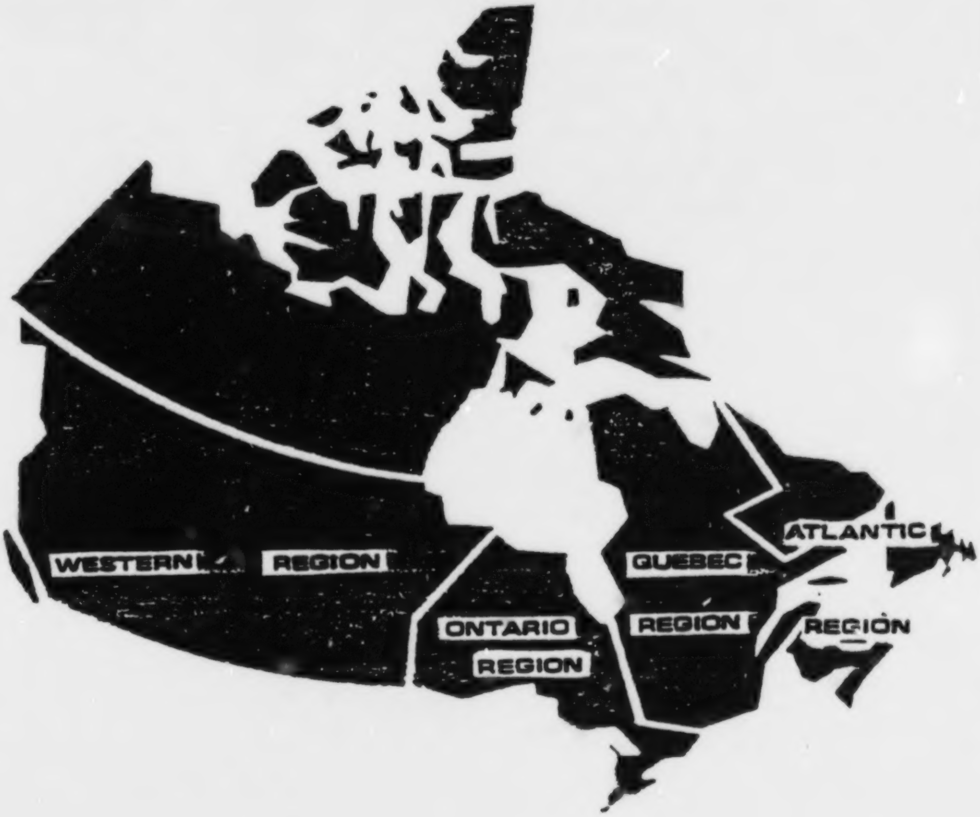

WESTERN
REGION
ONTARIO
REGION
QUEBEC
REGION
ATLANTIC
REGION

Figure 3.0.1 DEFINITION OF REGIONS IN CANADA

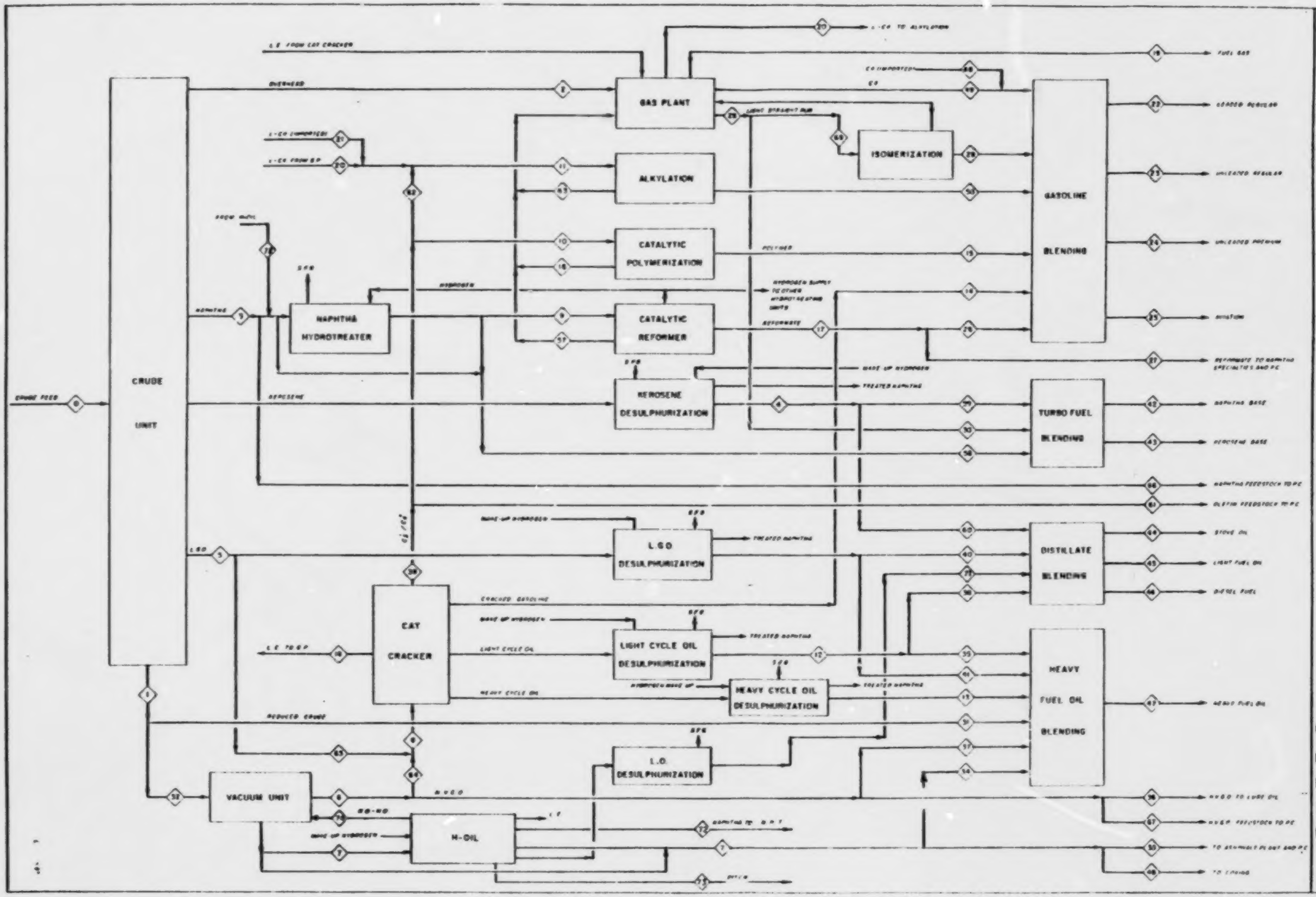

CRUDE FEED
CRUDE UNIT
OVERHEAD
NAPHTHA
KEROSENE
L.G.O.
REDUCED CRUDE
GAS PLANT
ALKYLATION
CATALYTIC POLYMERIZATION
CATALYTIC REFORMER
NAPHTHA HYDROTREATER
KEROSENE DESULPHURIZATION
ISOMERIZATION
L.G.O DESULPHURIZATION
CAT CRACKER
LIGHT CYCLE OIL DESULPHURIZATION
HEAVY CYCLE OIL DESULPHURIZATION
L.O. DESULPHURIZATION
VACUUM UNIT
H-OIL
GASOLINE BLENDING
TURBO FUEL BLENDING
DISTILLATE BLENDING
HEAVY FUEL OIL BLENDING
H.V.G.O
FUEL GAS
LEADED REGULAR
UNLEADED REGULAR
UNLEADED PREMIUM
AVIATION
REFORMATE TO NAPHTHA SPECIALTIES AND PC
NAPHTHA BASE
KEROSENE BASE
NAPHTHA FEEDSTOCK TO PC
OLEFIN FEEDSTOCK TO PC
STOVE OIL
LIGHT FUEL OIL
DIESEL FUEL
HEAVY FUEL OIL
H.V.G.O TO LUBE OIL
H.V.G.O FEEDSTOCK TO PC
TO ASPHALT PLANT AND PC
TO COKING
LEGEND
S.F.G. SOUR FUEL GAS
H.V.G.O. HEAVY VACUUM GAS OIL
L.G.O. LIGHT GAS OIL
L.E. LIGHT ENDS (C4 AND LIGHTER)
G.P. GAS PLANT
F.G. FUEL GAS
P.C. PETROCHEMICAL PLANT
◇ STREAM I.D. No. ON COMPUTER PRINTOUTS

FIGURE 3.1.1
BLOCK FLOW DIAGRAM OF REFINERY MODEL (Including Hydrotreating Units)

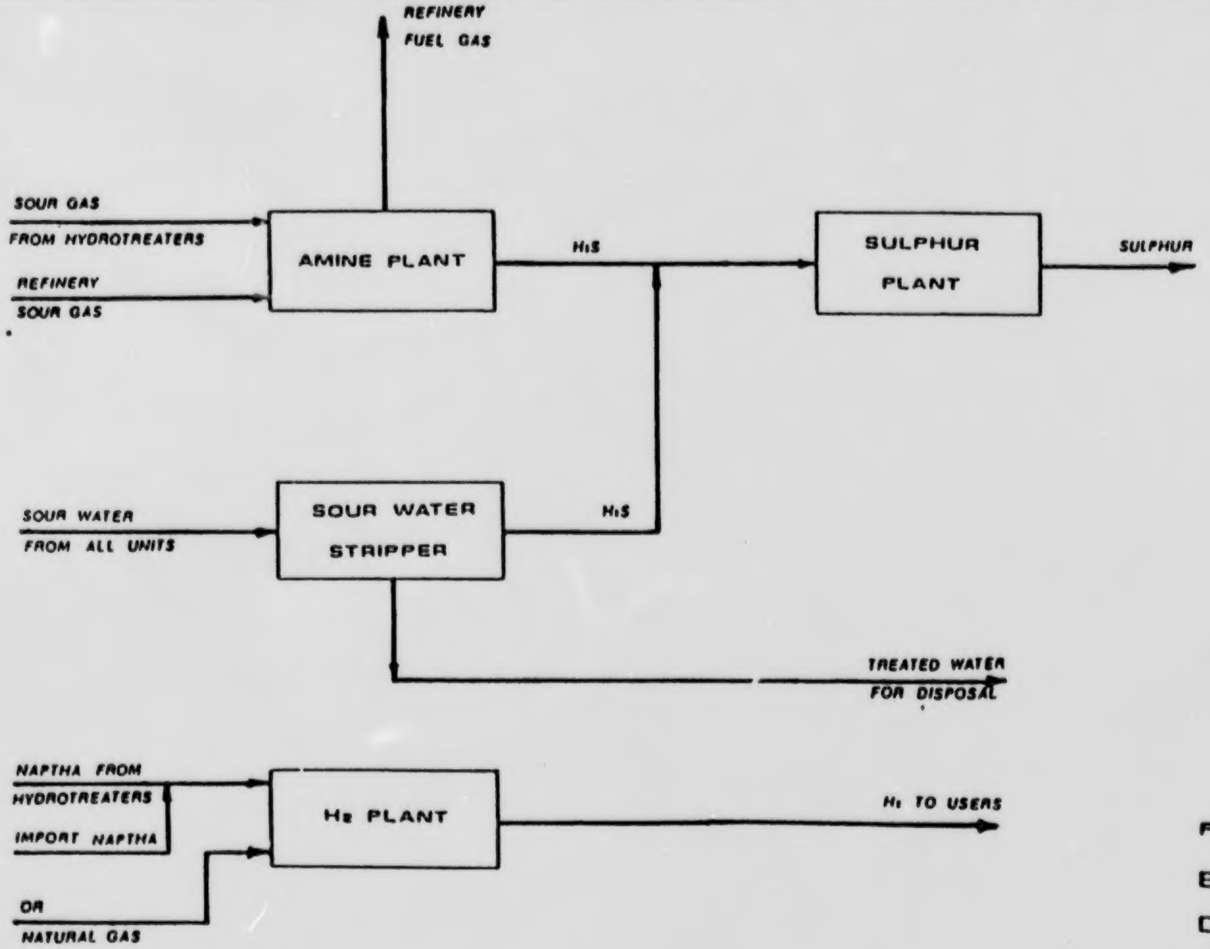

REFINERY FUEL GAS
SOUR GAS FROM HYDROTREATERS
REFINERY SOUR GAS
AMINE PLANT
H_2S
SULPHUR PLANT
SULPHUR
SOUR WATER FROM ALL UNITS
SOUR WATER STRIPPER
H_2S
TREATED WATER FOR DISPOSAL
NAPTHA FROM HYDROTREATERS
IMPORT NAPTHA
OR NATURAL GAS
H_2 PLANT
H_2 TO USERS

FIGURE 3.1.2
BLOCK FLOW DIAGRAM OF REFINERY AUXILIARY SYSTEMS

3.2 Execution of Simulation

The computation in the computer model was based on the following logic for this study:

(a) The liquid product stream rates and targeted quality spec. were defined. The property of crude feed, lead concentration for the gasoline products as well as the installed capacities of each process unit were also known.

(b) By assigning operating throughput and major operating parameters such as severity for the catalytic process units, cut points for the distillation units and splitting or blending criteria of the major streams, a mass balance of the refinery complex could be developed by interative technique. This mass balance gave the crude feed required, and the splitting or blending ratio of different streams to achieve the desired product rates and product qualities. The fuel gas product rate was a floating parameter for satisfying the mass balance.

(c) The objective of each simulation was to minimize the crude feed rate while maintaining the process unit throughput within the defined installed capacities and process capabilities.

(d) For this study, the product quality objective generally was achieved in two steps. First the material balance was developed to satisfy the product quality objectives other than the sulfur content spec. Subsequently, the sulfur content was re-calculated by minor adjustment of the mass balance and varying throughputs of the hydrotreating units. The refinement of sulfur balance and hydrotreater throughput optimization was not done in the computer model. In the mass balance refinement program, the overall throughputs of hydrotreating units were minimized to achieve the sulfur content required for a product which was a blend of two or more streams. This was done by hydrotreating the contributing streams which have the higher sulfur content (and therefore higher sulfur reduction potential) first, while maintaining the other quality spec. In this optimization process, it was also assumed that the hydrotreating units can be by-passed to produce desulfurized blending stocks of different sulfur levels for different final products such that the overall hydrotreater throughput in barrel/day was minimal. The adjusted percent by-pass on the computer printout (Part II) is therefore a time-average of each hydrotreater operation representing the most efficient utilization of the capacities, that can be achieved in practice. This approach was adopted to provide a consistent basis for comparison between cases.

(e) Product Quality Estimation

The pseudocomponent approach was used to estimate the properties of distillates, turbo fuels and heavy fuel oil. The true boiling point curve for each crude was divided into pseudocomponents of 20°F boiling range. Each psuedocomponent was assigned a specific gravity, mid boiling point and sulfur content as specified by the crude assay. Using procedures provided in the API Data Book (22), the pseudocomponent composition of each product was used to estimate ASTM distillation, specific gravities and characterization factors. These in turn were used to estimate the product qualities such as viscosity, flash points, and pour points based on various published and in-house correlations. In particular, diesel cetane index was estimated using the ASTM calculations procedure (23).

The pseudocomponent approach was not used for estimating gasoline properties. Table 3.2.1 summarizes the RVP and RON used for each gasoline component. The RON values shown are in line with recently published figures (15). Octane blending, including the effect of lead additives was based on a method by Eastman (24). RVP's for each gasoline grade were obtained by blending on a molar basis.

(f) Crude Diet Calculation

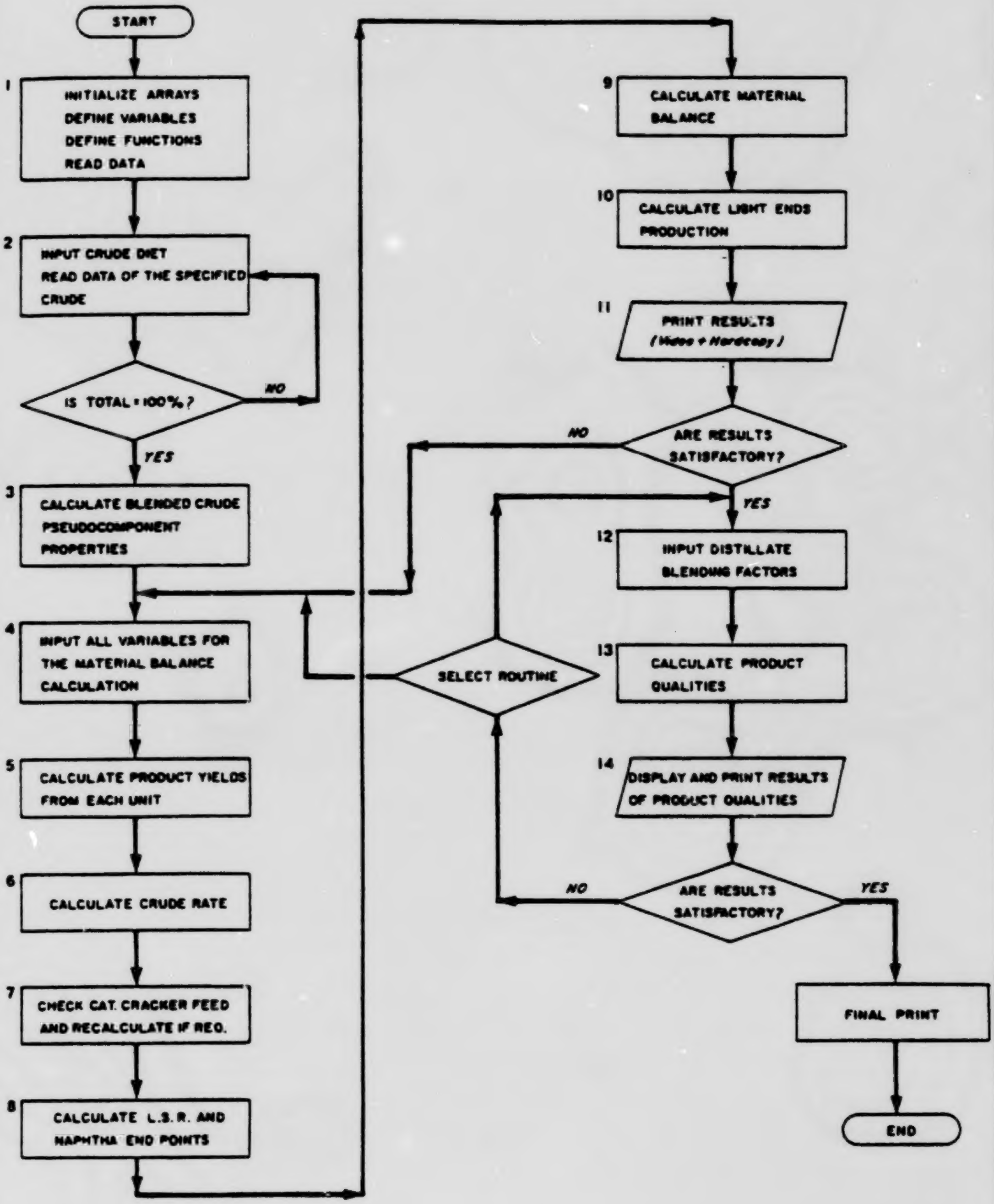
The model also includes a calculation routine for developing crude feed property based on a blend of different crudes which property data have been stored in the program.

The computation sequence of the simulation is summarized in the flowchart in Figure 3.2.1.

TABLE 3.2.1

GASOLINE COMPONENT PROPERTIES

	RVP	RON
Reformate	5.0	As specified for each case
Alkylate	8.5	93.
Polymer	4.5	96.5
Crackate	4.5	Varies between 89 and 92.2 depending on conversion
Light Straight Run (LSR)	From crude assay data	From crude assay data
Isomerate	Same as for LSR	RON of LSR +13.0
C_4	55.	93.


START
1
INITIALIZE ARRAYS
DEFINE VARIABLES
DEFINE FUNCTIONS
READ DATA
2
INPUT CRUDE DIET
READ DATA OF THE SPECIFIED CRUDE
IS TOTAL = 100% ?
NO
YES
3
CALCULATE BLENDED CRUDE PSEUDOCOMPONENT PROPERTIES
4
INPUT ALL VARIABLES FOR THE MATERIAL BALANCE CALCULATION
5
CALCULATE PRODUCT YIELDS FROM EACH UNIT
6
CALCULATE CRUDE RATE
7
CHECK CAT. CRACKER FEED AND RECALCULATE IF REQ.
8
CALCULATE L.S.R. AND NAPHTHA END POINTS
9
CALCULATE MATERIAL BALANCE
10
CALCULATE LIGHT ENDS PRODUCTION
11
PRINT RESULTS
(Video + Hardcopy)
ARE RESULTS SATISFACTORY?
NO
YES
SELECT ROUTINE
12
INPUT DISTILLATE BLENDING FACTORS
13
CALCULATE PRODUCT QUALITIES
14
DISPLAY AND PRINT RESULTS OF PRODUCT QUALITIES
ARE RESULTS SATISFACTORY?
NO
YES
FINAL PRINT
END

FLOWCHART FOR REFINERY SIMULATION FIG. 3.2.1

3.3 Addition of H-Oil Process Unit

The integration of the H-Oil process unit originally envisaged in the inquiry document (Refer to Appendices) was as follows:

The vacuum resid is hydrocracked in the reactor and the cracked products are separated in the atmospheric fractionator into gas, naphtha, distillate and gas oil. The atmospheric fractionator bottom is heated and flashed under vacuum in a flash separator which vapour is returned to the existing vacuum tower.

For simplicity, the flowscheme developed by HRI which has an independent vacuum tower instead of a vacuum flash separator was used for modelling and as basis of cost estimate in this study. This was considered an aceeptable approach as the vacuum tower and the associated equipment constitute only a very small proportion of the capital investment of the H-Oil process. The overall mass balances for the two schemes are practically the same for the purpose of this study. The actual optimum scheme for integrating the H-Oil unit, which is beyond the scope of this study, probably would favor the simpler flash separator version and naturally would require further analysis based on the situation of the individual plant.

The H-Oil flowscheme and its integration into the refinery model is illustrated in Figure 3.3.1. Fuel gas from the H-Oil process is integrated into the refinery fuel gas system after sweetening. This stream is not depicted in the main program commputer print-out (Part I) but is shown in the print-out of mass balance refinement programs (Part II). The naphtha cut is used as catalytic reformer feed after hydrotreating. The distillate/light gas oil cut (named HO-LO in print-out) is used for blending to produce diesel fuel or light fuel oil. The gas oil (named HO-HO in print-out) is mixed with the heavy vacuum gas oil which destines for catalytic cracker feed or HVGO products. Background information on process yield and product quality of the H-Oil unit are provided in Section 3.5.5.

The H-Oil process unit is only used in the simulation of cases 3, 4, 5 and 6, and is 100% by-passed in the simulation of cases 1 and 2.

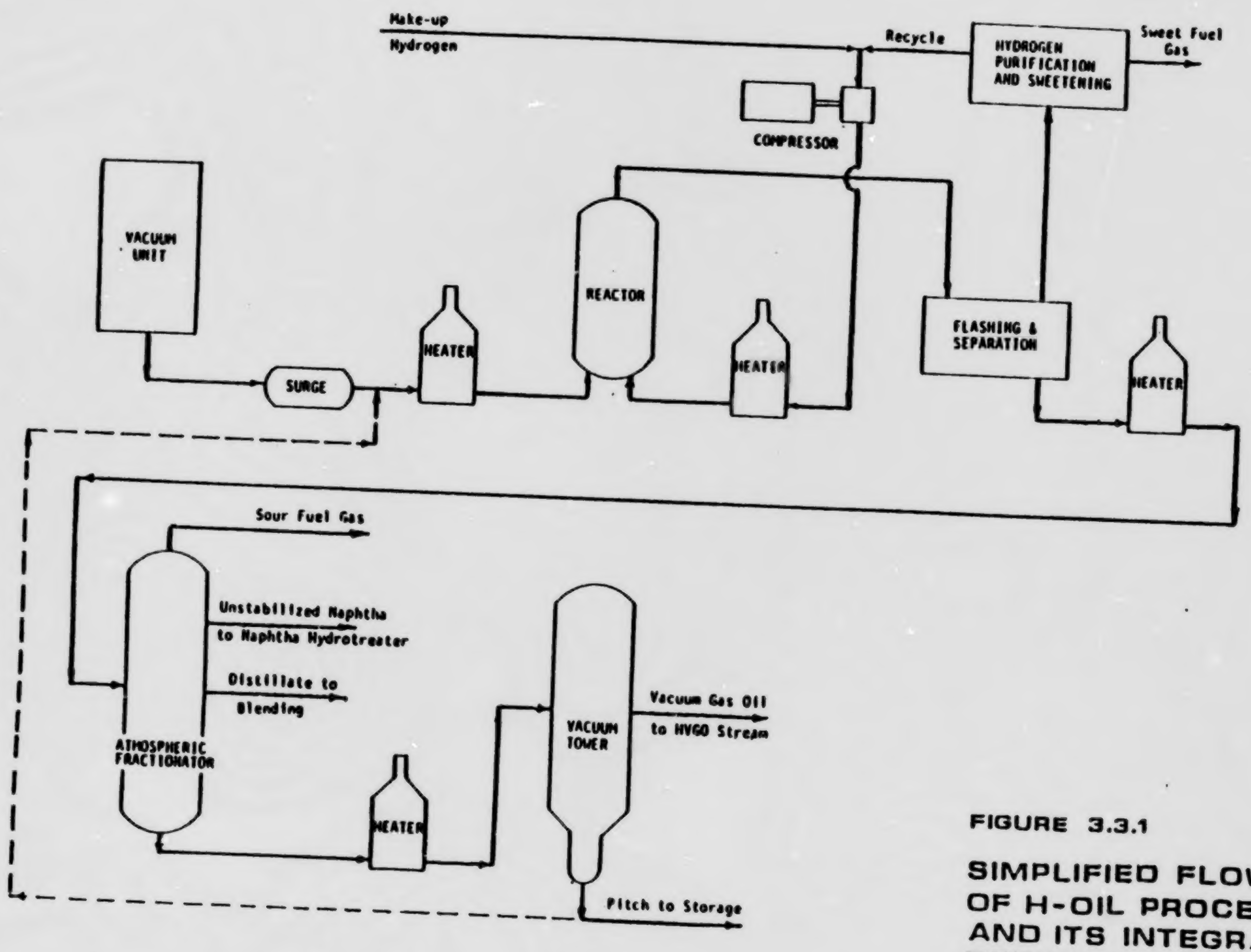

Make-up
Hydrogen
Recycle
HYDROGEN PURIFICATION AND SWEETENING
Sweet Fuel Gas
COMPRESSOR
VACUUM UNIT
SURGE
HEATER
REACTOR
HEATER
FLASHING & SEPARATION
HEATER
Sour Fuel Gas
Unstabilized Naphtha to Naphtha Hydrotreater
Distillate to Blending
ATMOSPHERIC FRACTIONATOR
HEATER
VACUUM TOWER
Vacuum Gas Oil to HVGO Stream
Pitch to Storage

FIGURE 3.3.1

SIMPLIFIED FLOW DIAGRAM OF H-OIL PROCESS UNIT AND ITS INTEGRATION INTO REFINERY COMPLEX.

3.4 Program for Mass Balance Refinement and Utility Data Handling

The mass balance refinement section of the program performed the following functions after simulation by the computer model had been carried out:-

(a) The throughput of the hydrotreaters were optimized to satisfy exactly the sulfur content requirement of the products.

(b) Based on the hydrotreater yield data described in Section 3.5.4, the mass balances around the hydrotreaters were adjusted to account for the production of sour gas and naphtha and the feed rates were adjusted accordingly. As a result of the hydrotreaters mass balance adjustment, minor adjustments on some other streams calculated earlier by the computer model were also necessary. The very small adjustments on the catalytic cracker conversion are not shown on the print-outs. Crude feed rates always remain unaffected. The adjustments are summarized in Part II of the computer print-outs (Page 8).

The utility data handling section of the program calculated and tabulated the utility and energy requirements and the corresponding incremental requirements compared to the reference base case. Throughputs of amine unit and sulfur were also calculated. The results are in Part II of the computer print-outs (Pages 9 - 11).

3.5 Basis of Process Parameters

The basis used for computer simulation and cost estimates were developed based on the scope definition as described below.

3.5.1 Crude Diets

The quantities of crude oils used by Canadian refineries in 1981 were reported by Statistics Canada (3) by country of origin, however no indication was given of the qualities since each reported figure was, in fact, a composite of several grades.

For a study of the type undertaken in this report, it is essential to have not only detailed information on the individual crude oil qualities but also information that is truely representative of the situation as it existed in the year under study. Thus additional sources of data have had to be sought and adjustments made in order to arrive at a set of regional crude oil diets that corresponded to reality not only in terms of quantity but also in quality. This aspect was especially true in the case of sulfur levels since this topic is the major concern of the study.

With the assistance of Environment Canada and Energy, Mines and Resources, it was possible to segregate the various crude oils into light, medium, heavy and synthetic grades and to assign an appropriate crude assay to the major components of the slates. Any crude, whose quantity was relatively small and could not be readily identified with a known assay, was included with one of the major components whose gravity is similar (14).

Since there was some uncertainty in the sulfur content in the crude assay, the total sulfur content of the crude diet of each region was adjusted according to the confidential information provided by Environment Canada. The sulfur distribution among various cuts of the crude was assumed to be unchanged.

The crude diets developed as described are presented in Tables 3.5.1.1 to 4.

TABLE 3.5.1.1

ATLANTIC REGION CRUDE DIET 1981

CRUDE ORIGIN	LV%
Venezuela Light	22
Venezuela Heavy	3.5
Arab Light	58.8
North Sea	8.9
Mex Light	4.3
Mex Heavy	2.5
	100.0

Actutal Throughput, BPCD	215,437
Gravity, °API	32.5
Sulfur, Wt.%	1.564

TABLE 3.5.1.2

QUEBEC REGION CRUDE DIET 1981

CRUDE ORIGIN	LV%
Venezuela Light	11.69
Venezuela Heavy	6.41
Arab Light	15.1
Condensate	2.3
Syncrude	5
Domestic Heavy	7.3
Domestic Light	37.6
North Sea	7.2
Mex Light	3.98
Mex Heavy	2.92
	100.0

Actual Throughput, BPCD	474,261
Gravity, °API	33.5
Sulfur, Wt.%	1.141

TABLE 3.5.1.3

ONTARIO REGION CRUDE DIET 1981

CRUDE ORIGIN	LV%
Condensate	5.2
Syncrude	5.9
Domestic Heavy	9.2
Domestic Light	79.7
	100.0

Actual Throughput, BPCD	553,138
Gravity, °API	38.26
Sulfur, Wt.%	0.597

TABLE 3.5.1.4

WESTERN REGION CRUDE DIET 1981

CRUDE ORIGIN	LV%
Condensate	5.85
Syncrude	6.9
Domestic Heavy	5.45
Domestic Light	78.6
Butane	3.2
	100.0

Actual Throughput, BPCD	513,629
Gravity, °API	40.5
Sulfur, Wt.%	0.503

3.5.2 Product Slates and Specifications

3.5.2.1 Product Slates

The 1981 petroleum products data reported as "Net Production" by Statistics Canada (3) were used as 1981 production figures for each region - Net Production of gasolines was reported for the total product, rather than for each grade. The production figures of each grade which had to be defined for simulation was therefore taken to be proportional to sales data which were also available in the same reference.

Additional information was required to estimate the relative amount of various types of petrochemical feedstocks, such as olefins and naphtha. This was done in the same manner as previous studies (4, 5) based on the capacities of petrochemical plants as published in Oil Week (19).

The product slates for the four regions and Canada are presented in Tables 3.5.2.1 to 5. Crude oil feed rates are included in the tables for reference. The flowrates of crude feed and that of fuel gas shown in brackets, were results from the base case simulation, which will be discussed in a later section.

TABLE 3.5.2.1

TOTAL PRODUCT SLATE FOR 1981

ATLANTIC REGION, (BASE CASE)

PRODUCT	BPCD	VOL. %
FUEL GAS (FOE) (float)	(11,010)	5.00
LEADED REGULAR GASOLINE	34,573	15.70
UNLEADED REGULAR GASOLINE	24,713	11.22
UNLEADED PREMIUM GASOLINE	5,578	2.53
AVIATION GASOLINE	0	0
NAPHTHA SPECIALTIES	0	0
OLEFIN PETROCHEMICAL FEED	468	0.21
NAPHTHA PETROCHEMICAL FEED	0	0
JET FUEL B (NAPH. BASE)	2,011	0.91
JET FUEL A (KERO. BASE)	6,145	2.79
STOVE OIL	3,325	1.51
DIESEL FUEL	16,969	7.71
LIGHT FUEL OIL (#2 & 3)	56,764	25.77
HEAVY FUEL OIL (#4, 5 & 6)	52,516	23.84
LUBE OIL	0	0
ASPHALT	4,939	2.24
COKE	1,250	0.57
TOTAL PRODUCT	220,261	100.00
CRUDE OIL FEED (Reported)	215,437	
CRUDE OIL FEED (from simulation)	(220,692)	

TABLE 3.5.2.2

TOTAL PRODUCT SLATE FOR 1981

QUEBEC REGION, (BASE CASE)

PRODUCT	BPCD	VOL. %
FUEL GAS (FOE) (float)	(27,888)	5.76
LEADED REGULAR GASOLINE	74,979	15.48
UNLEADED REGULAR GASOLINE	49,138	10.15
UNLEADED PREMIUM GASOLINE	30,161	6.23
AVIATION GASOLINE	1,229	0.25
NAPHTHA SPECIALTIES	4,032*	0.83
OLEFIN PETROCHEMICAL FEED	1,660	0.34
NAPHTHA PETROCHEMICAL FEED	17,376	3.59
JET FUEL B (NAPH. BASE)	4,130	0.85
JET FUEL A (KERO. BASE)	13,448	2.78
STOVE OIL	4,844	1.00
DIESEL FUEL	49,942	10.31
LIGHT FUEL OIL (#2 & 3)	78,890	16.29
HEAVY FUEL OIL (#4, 5 & 6)	102,591	21.19
LUBE OIL	3,511	0.73
ASPHALT	18,175	3.75
COKE	2,268	0.47
TOTAL PRODUCT	484,262	100.00
CRUDE OIL FEED (Reported)	474,261	
CRUDE OIL FEED (from simulation)	(484,623)	

* Including 3,099 BPCD for P.C. Feedstock.

TABLE 3.5.2.3

TOTAL PRODUCT SLATE FOR 1981

ONTARIO REGION, (BASE CASE)

PRODUCT	BPCD	VOL. %
FUEL GAS (FOE) (float)	(31,849)	5.57
LEADED REGULAR GASOLINE	112,717	19.71
UNLEADED REGULAR GASOLINE	74,149	12.97
UNLEADED PREMIUM GASOLINE	21,959	3.84
AVIATION GASOLINE	217	0.04
NAPHTHA SPECIALTIES	13,000*	2.27
OLEFIN PETROCHEMICAL FEED	6,357	1.11
NAPHTHA PETROCHEMICAL FEED	55,332	9.68
JET FUEL B (NAPH. BASE)	3,773	0.66
JET FUEL A (KERO. BASE)	16,446	2.88
STOVE OIL	4,522	0.79
DIESEL FUEL	55,130	9.64
LIGHT FUEL OIL (#2 & 3)	66,403	11.61
HEAVY FUEL OIL (#4, 5 & 6)	87,612	15.32
LUBE OIL	9,122	1.60
ASPHALT	8,883**	1.55
COKE	4,362	0.76
TOTAL PRODUCT	571,833	100.00
CRUDE OIL FEED (Reported)	553,138	
CRUDE OIL FEED (from simulation)	(565,954)	

* Including 2,010 BPCD for P.C. Feedstock.
** Including 1,168 BPCD for P.C. Feedstock.

TABLE 3.5.2.4

TOTAL PRODUCT SLATE FOR 1981

WESTERN REGION, (BASE CASE)

PRODUCT	BPCD	VOL. %
FUEL GAS (FOE) (float)	(42,577)	8.03
LEADED REGULAR GASOLINE	166,593	31.40
UNLEADED REGULAR GASOLINE	51,363	9.68
UNLEADED PREMIUM GASOLINE	11,071	2.07
AVIATION GASOLINE	2,832	0.54
NAPHTHA SPECIALTIES	1,287	0.24
OLEFIN PETROCHEMICAL FEED	0	0
NAPHTHA PETROCHEMICAL FEED	967	0.18
JET FUEL B (NAPH. BASE)	18,744	3.54
JET FUEL A (KERO. BASE)	13,976	2.64
STOVE OIL	9,888	1.86
DIESEL FUEL	126,335	23.81
LIGHT FUEL OIL (#2 & 3)	20,082	3.79
HEAVY FUEL OIL (#4, 5 & 6)	33,057	6.23
LUBE OIL	3,914	0.74
ASPHALT	21,693	4.09
COKE	6,143	1.16
TOTAL PRODUCT	530,522	100.00
CRUDE OIL FEED (Reported)	513,629	
CRUDE OIL FEED (from simulation)	(534,463)	

TABLE 3.5.2.5

TOTAL PRODUCT SLATE FOR 1981

CANADA

PRODUCT	BPCD	VOL. %
FUEL GAS (FOE) (float)	(113,324)	6.27
LEADED REGULAR GASOLINE	388,862	21.52
UNLEADED REGULAR GASOLINE	199,363	11.03
UNLEADED PREMIUM GASOLINE	68,769	3.81
AVIATION GASOLINE	4,278	0.24
NAPHTHA SPECIALTIES	18,319*	1.01
OLEFIN PETROCHEMICAL FEED	8,485	0.47
NAPHTHA PETROCHEMICAL FEED	73,675	4.08
JET FUEL B (NAPH. BASE)	28,658	1.59
JET FUEL A (KERO. BASE)	50,015	2.77
STOVE OIL	22,579	1.25
DIESEL FUEL	248,376	13.74
LIGHT FUEL OIL (#2 & 3)	222,139	12.29
HEAVY FUEL OIL (#4, 5 & 6)	275,776	15.26
LUBE OIL	16,547	0.92
ASPHALT	53,690**	2.97
COKE	14,023	0.78
TOTAL PRODUCT	1,806,878	100.00
CRUDE OIL FEED (Reported)	1,756,465	
CRUDE OIL FEED (from simulation)	(1,805,732)	

* & ** see notes on earlier tables.

3.5.2.2 Product Specifications

Quality of the products other than sulfur contents which were defined in the study objectives, were established based on the specification published by Canadian General Standards Board (18), and in-house data. The number of product categories were kept to a minimum to facilitate computer simulation. For those categories of products such as kerosenes and fuel oils which have different specs. for different types or grades of commercial products, the most stringent spec. or the spec. of the dominating contributor in a category were adopted.

Data on lead addition to gasoline in each region were derived from the confidential information provided by Environment Canada (17).

The basis of product quality used for the study is summarized in Table 3.5.2.6.

TABLE 3.5.2.6

GENERAL PRODUCT SPECIFICATIONS 1981

Leaded Regular Gasoline

Octane No.	$\frac{RON + MON}{2}$	88 (min.)
RVP	psia	9 - 14
Lead Content	g/l	0.77 (max.) 0.54 (Atlantic actual) 0.58 (Quebec actual) 0.38 (Ontario actual) 0.40 (Western actual)

Unleaded Regular Gasoline

Octane No.	$\frac{RON + MON}{2}$	87 (min.)
Motor Octane No.	MON	82
RVP	psia	9 - 14

Unleaded Premium Gasoline

Octane No.	$\frac{RON + MON}{2}$	90 (min.)
Motor Octane No.	MON	82
RVP	psia	9 - 14

Aviation Gasoline

Octane No.	RON	93.0 (min.)
RVP	psia	10.0 (max.)

Table 3.5.2.6 (Cont'd)

Turbo Fuel Jet B (Naphtha Base)

Specific Gravity		0.750 - 0.801
ASTM Distillation % 20/50/90, °F		290/370/470 (max.)
RVP	psia	2 - 3
Sulfur	wt.%	0.4 (max.)

Turbo Fuel Jet A (Kerosene Base)

Specific Gravity		0.774 - .839
Pour Point, °F		- 50 (max.)
ASTM Distillation 10%, °F		400 (max.)
Flash Point	°F	90 (max.)
Sulfur	wt.%	0.2 (max.)

Diesel Fuel

Pour Point	°F	- 25 (max.)
Specific Gravity		.816 - 0.855
ASTM Distillation % 90, °F		625 (max.)
Flash Point	°F	104 (min.)
Cetane Index		40 (min.)
Viscosity @ 104°F,	CS	1.3 - 4.1
Sulfur	wt.%	0.2 (max.)* 0.5 (max.)** 0.7 (max.)***

Stove Oil/Kerosene

Pour Point	°F	- 35 (max.)
Specific Gravity		0.85 (max.)
ASTM Distillation % 10/90, °F		420/520 (max.)
Flash Point	°F	104 (min.)
Viscosity @ 104°F,	CS	1.25 (min.)
Sulfur	wt.%	0.13 (max.)

Table 3.5.2.6 (Cont'd)

Light Fuel Oil (#2)

Pour Point	°F	0 (max.)
Specific Gravity	Max.	0.9
ASTM Distillation % 90,	°F	680 (max.)
Flash Point	°F	104 (min.)
Viscosity @ 104°F	CS	1.6 - 3.6
Sulfur	wt.%	0.7 (max.)

Heavy Fuel Oil (#4, #5 & #6)

Viscosity @ 122°F,	CS	638 (max.)
Sulfur	wt.%	3.5 (max.)

NOTES:

*	For Western Region
**	For Ontario & Quebec
***	For Atlantic Region

3.5.2.3 Refinery's Own Fuel Consumption, Saleable Heavy Fuel Oil and Light Fuel Oils

The "refinery's own fuel consumption" consists mainly of HFO (#4, #5 and #6) and relatively small amounts of LFO (#2 & #3), diesel fuel and stove oil/kerosene. The data were derived from Statistics Canada's "Refined Petroleum Products, Dec. 1981" (3). The saleable heavy fuel oil and light fuel oils included imports/exports and interprovincial transfers. They were calculated from StatsCan's "Net Production" figures by the following formula:

Saleable Product = Net Production + Stock - Losses -
Own Consumption

The "refinery's own fuel consumptions" which were used for sulfur reduction calculation were only a small portion of the Net Production. They were assumed to be constant for all cases and not tied in with the energy requirements of the study cases.

3.5.3 Installed Capacities of Process Units

3.5.3.1 Installed Capacities of Major Process Units

The installed refinery process unit capacities in 1981 were taken from EMR's "Petroleum Refineries in Canada", December, 1981 (1), which describes all refineries in operation in that year.

Those process units which are directly related to this study are presented in Tables 6.2.3.1 to 4, in Section 6. It should be noted that the capacities are expressed in barrels per calendar day (BPCD) rather than in barrels per stream day (BPSD). An on stream factor of 0.89 was assumed for the conversion.

The refinery at Point Tupper was not in operation in 1981 (was used as a marketing terminal); therefore its installed capacity was not included.

In accordance with the computer model described earlier, hydrocracking unit capacities were included in the catalytic cracking unit capacities.

3.5.3.2 Installed Capacities of Hydrotreating Units

The installed capacities of naphtha, distillate and gas oil hydrotreaters were reported in the EMR's publication (1). However, apart from the naphtha hydrotreaters, the distribution of the hydrotreating capacities among the distillate hydrotreaters was not elaborated in the publication. Since the requirement of additional hydrotreating capacities for different feedstocks is one of the concerns in this study, certain rationale was used to establish the basis of installed capacities of the different hydrotreaters.

The installed capacities of naphtha hydrotreaters used for the study are as stated in the EMR's publication. The capacities of distillate hydrotreaters as reported by EMR were split into those of kerosene, LGO and LCO. The capacities of gas oil hydrotreating as reported by EMR were split into those of LCO and HCO. The calculated capacities were then collated with the computer simulation results of the reference base case, knowing that the installed capacities were more than required in 1981. Refinement was then made to establish the basis for this study. This basis of hydrotreating capacities is consistent with the basis established for 1979 in the previous study (5). It is recognised that the calculated distribution of hydrotreating capacities may not be exactly what the refineries have, it nevertheless provides a reasonable basis for quantitative comparison among the study cases and the reference base case.

The basis of installed capacities of hydrotreaters are shown in Tables 6.2.3.5 to 8 in Section 6.

3.5.3.3 Installed Capacities of Sulfur Plants and Sour Water Strippers

A. Sulfur Plant

The installed capacities of sulfur recovery plants were derived from the EMR's publication (1) and the PACE report (20). The data from these references generally agreed with each other. Some discrepancies can be rationalized as incomplete information in either of the publications.

Estimated installed capacities used as the basis in this study are shown with the source data in Table 3.5.3.1.

TABLE 3.5.3.1

INSTALLED SULFUR RECOVERY PLANT CAPACITIES

	EMR'S DATA (Ref. 2) ST/CD	PACE DATA (Ref. 20) ST/CD	BASIS OF THIS STUDY ST/CD
Atlantic	307	277	307
Quebec	-	312*	312
Ontario	283	325	325
Western	164	147	164

* Most of this capacity belongs to the common sulfur recovery facilities serving the refineries in the Montreal area.

B. Sour Water Stripper

The installed capacities of refinery sour water strippers in 1981 were estimated as shown in Table 3.5.3.2. They were calculated from the reference base case SWS throughput, based on a unit utilization factor assumed to be the same as that of crude unit of the same case.

TABLE 3.5.3.2

INSTALLED SOUR WATER STRIPPER CAPACITIES

	UTILIZATION FACTOR	INSTALLED CAPACITY BPCD
Atlantic	0.623	6,837
Quebec	0.822	8,102
Ontario	0.749	5,971
Western	0.994	5,620

3.5.4 Hydrotreater Product Yields

Yield data for the hydrotreaters (5, 7) used for the mass balance adjustments are summarized in Table 3.5.4.1. Sour fuel gas includes hydrogen and C_4.

TABLE 3.5.4.1

HYDROTREATER PRODUCT YIELDS

Basis: 10,000 BPCD Feed

HYDROTREATER	SULFUR REMOVAL %	SOUR FUEL GAS INCL. C_4		TOTAL NAPHTHA C_5 - 375°F BPCD	TOTAL FUEL OIL 375°F+ BPCD	SOUR WATER LB/LB Feed
		LHV BTU/SCF	MSCF/D			
Naphtha	100	771	680	10,000	-	0.038
Kerosene	95	673	990	30	10,020	0.053
LGO, HO-LO	90	758	1240	90	10,000	0.05
LCO	90	758	1240	107	9,860	0.06
HCO	85	758	1500	150	9,850	0.075

3.5.5 H-Oil Process Product Yields

The H-Oil process is an ebullated-bed reactor hydrocracking process developed by Hydrocarbon Research Inc. (HRI). The chemistry involves thermal cracking in the presence of hydrogen for basic conversion and quality improvement by adding hydrogen for hydrocracking, aromatics saturation and heteroatom removal. In this study, the process is used to crack the vacuum resid in the refineries to lighter products which can be used for feeding catalytic cracker and reformer or for product blending. The result of vacuum resid conversion is the reduction of heavy fuel oil production and hence reduction in crude oil requirement.

The simplified process flow diagram has been presented in Section 3.3. The requirement of recycle from vacuum bottom to the reactor is determined by conversion level defined as percent of $975^{0}F^{+}$ in feed converted to lighter products. Recycle is necessary for 90 LV% conversion but is not required for 66 LV% conversion. For an optimum design, two stage reactors may be required for feedstock with high metal content to achieve reasonable catalyst consumption. Discussions with the process licensor indicated that 300 ppm Ni and V is the approximate upper limit within which the single stage reactor can be used. The metal contents of the vacuum resid from the four regions (Approx: Atlantic 178 wppm, Quebec 207 wppm, Ontario 72 wppm and Western 62 wppm) are all below this metal level; therefore the single stage reactor configuration can be used. The process configuration and the capital investment of the H-Oil process are also affected by other feedstock properties such as gravity, carbon content and chemical composition which could be better characterized by the origin of the crude.

The product yield and property data of H-Oil process used for this study of which the prime objective is conversion of vacuum resid to lighter products were developed from MHG in-house data, the past study data from HRI and study (high conversion of vacuum resid, Quebec region) done by HRI on MHG's contract (30). Product yield, product quality and utility data projections were done based on data for vacuum resids from crudes of the same origins or similar properties. The data developed as such, naturally have some uncertainties, nevertheless, they are adequate for the purpose of this study which is based on the composite refinery concept.

Different sets of data were developed for the two levels of conversion, and for vacuum resids of the four different regions. The essential yield data are presented in Tables 3.5.5.1 and 3.5.5.2. Since the crude for Ontario and Western regions were very similar, the same liquid yield data have been used. This may not be obvious in the tables because different cut points were used in order to integrate the products into the rest of the refinery.

The cracked products from the H-Oil process are sent to the process units or product blending pools which are compatible with their qualities. The comparison is based mostly on the data of vacuum resid of the Quebec region which were provided by the process licensor (30).

(a) Naphtha product contains some olefins which can be saturated by hydrotreating. Its sulfur content is somewhat higher than that of the virgin naphtha from the same crude but should be well within the capability of the naphtha hydrotreater. The paraffins, naphtenes and aromatic contents are within the ranges which can be reformed for gasoline production. This stream is therefore blended with the virgin naphtha which is hydrotreated before going to the catalytic reformer.

(b) Distillate/light gas oil product cetane number is within the spec. of diesel fuel oil (min. cetane no. = 40). The sulfur content of this hydrocracked product is lower than the untreated LGO and LCO from the same crude. The pour point is within the spec. of light fuel oil. The distillate/light gas oil from H-Oil process is used as blending stock for diesel fuel oil and light fuel oil without further hydrotreating. Since it constitutes only a small fraction of the total blending stock, by manipulating the blending ratio and the desulfurization level of LGO and LCO, the specs. of diesel fuel oil and light fuel oil can all be achieved.

(c) Gas oil product sulfur content is comparable to that of HVGO and LGO which are used as catalytic cracker feedstock in the base case. It has been demetallized and contains a similar level of nitrogen as the vacuum resid. Since its quality is comparable to the quality of the base case catalytic cracker feed in most respects, it is blended into the HVGO which destines for catalytic cracker feed or lube production. The impact of nitrogen content on the cracker performance has not been investigated. The effect of blending gas oil from H-Oil process into the heavy vacuum gas oil, on the quality of catalytic cracker feed is usually rather minor considering the proportion of their flow rates. Nevertheless, they should be further investigated.

(d) H-Oil resid or pitch has been partially desulfurized in the hydrocracking process. It is highly viscous and probably contains a similar level of metal as that in the vacuum resid. According to the process licensor, the resid from the low conversion process can be blended with the lighter cutter stocks to achieve the desired viscosity for heavy fuel oil. However, the resid from the 90 LV% conversion cannot be used as blending stock for commercial heavy fuel oil because a stable blending cannot be achieved. The resids can however be consumed as fuel oil with special burner and by keeping it in fluid condition. It may also be used as feedstock for coking, gasification and asphalt manufacturing. These criteria for H-Oil resid utilization is adopted in the later section dealing with the simulation results analysis.

The discussion on deposition of the H-Oil process product is based on limited data available within the schedule of this study. No optimization has been carried out. A more indepth investigation is undoubtedly warranted when the specific refinery is analyzed.

Utility data for H-Oil process presented in other sections were developed using the same approach.

TABLE 3.5.5.1

BASIS OF H-OIL PROCESS YIELD AND PRODUCT PROPERTY 66 LV% CONVERSION OF 975°F

SOURCE OF VAC. RESID	ATLANTIC				QUEBEC				ONTARIO				WESTERN			
		YIELD	SP. GR.	S w%		YIELD	SP. GR.	S w%		YIELD	SP. GR	S w%		YIELD	SP. GR.	S w%
Gas Yield in w% of Feed	C_1	1.12			C_1	1.12			C_1	1.48			C_1	1.48		
	C_2	0.80			C_2	0.88			C_2	1.17			C_2	1.17		
	C_3	1.13			C_3	1.13			C_3	1.50			C_3	1.50		
	H_2S	2.76			H_2S	2.36			H_2S	1.64			H_2S	1.44		
Liquid Yield in Vol/Vol. of Feed	EBP,°F				EBP,°F				EBP,°F				EBP,°F			
Naphtha	318	0.11	0.715	0.13	345	0.135	0.72	0.12	367	0.16	0.75	0.06	329	0.145	0.745	0.05
Distillate/ Light Gas Oil	690	0.34	0.85	0.24	685	0.315	0.848	0.23	650	0.27	0.865	0.19	650	0.28	0.865	0.16
Heavy Gas Oil	975	0.30	0.92	0.76	975	0.30	0.92	0.65	975	0.25	0.94	0.40	975	0.255	0.9375	0.36
Resid/Pitch		0.323	1.043	1.83		0.323	1.043	1.58		0.32	1.07	1.38		0.34	1.07	1.23

TABLE 3.5.5.2

BASIS OF H-OIL PROCESS YIELD AND PRODUCT PROPERTY 90 LV% CONVERSION OF 975°F

SOURCE OF VAC. RESID	ATLANTIC				QUEBEC				ONTARIO				WESTERN			
		YIELD	SP. GR.	S w%		YIELD	SP. GR.	S w%		YIELD	SP.GR.	S w%		YIELD	SP. GR.	S w%
Gas Yield in w% of Feed	C_1	1.73			C_1	1.7			C_1	1.46			C_1	1.46		
	C_2	1.52			C_2	1.5			C_2	1.29			C_2	1.29		
	C_3	1.82			C_3	1.8			C_3	1.55			C_3	1.55		
	H_2S	2.88			H_2S	2.25			H_2S	1.71			H_2S	1.54		
Liquid Yield in Vol/Vol. of Feed	EBP, °F				EBP, °F				EBP, °F				EBP, °F			
Naphtha	317	0.16	0.705	0.06	346	0.164	0.73	0.17	384	0.167	0.735	0.05	329	0.15	0.73	0.04
Distillate/ Light Gas Oil	690	0.461	0.85	0.28	685	0.40	0.86	0.42	650	0.298	0.86	0.22	650	0.315	0.853	0.19
Heavy Gas Oil	975	0.369	0.962	1.25	975	0.435	0.993	1.22	975	0.48	0.9375	0.73	975	0.482	0.9375	0.65
Reisd/Pitch		0.095	1.115	2.11		0.095	1.123	1.92		0.102	1.0875	1.38		0.10	1.0875	1.23

3.5.6 Hydrogen Consumption

The basis of hydrogen consumption used for hydrotreaters were the same as those of previous study (5). They were developed based mostly on in-house data and partly on published information (2, 7, 21) and are summarized in Table 3.4.6.1. A general but conservative approach was adopted to establish these data in the absence of the process details of the existing hydrotreaters.

TABLE 3.5.6.1

HYDROGEN CONSUMPTION IN HYDROTREATING UNIT

HTU	Hydrogen (100%) Consumption SCF/Bbl Feed
Naphtha	100
Kerosene	300
LGO	500
LCO	700
HCO	1,000

Hydrogen consumption of the H-Oil process was developed from the in-house data and information provided by the licensor. It is influenced by the characteristics of the vacuum resid. Figures shown in Table 3.5.6.2 were the estimated hydrogen (based on 100% purity) required for treating the vacuum resids similar to those from the four regions. These hydrogen consumption rates include chemical hydrogen required and solution losses.

TABLE 3.5.6.2

HYDROGEN CONSUMPTION IN H-OIL UNIT

CASE \ REGION	ATLANTIC	QUEBEC	ONTARIO	WESTERN
H-Oil Low Conv. (66%) Case 3 & Case 4 SCF/Bbl Feed	1,397	1,313	787	787
H-Oil High Conv. (90%) Case 5 & Case 4 SCF/Bbl Feed	1,796	1,691	1,014	1,014

3.5.7 Sulfur Recovery

For sulfur recovery facilities larger than 100 STPD, a 99% minimum recovery efficiency is required as stated in Scope. A tail gas clean-up unit is required to achieve this recovery efficiency. For sulfur recovery facilities smaller than 100 STPD, the required sulfur recovery efficiency is 97% which is the limit a conventional three-stage Claus process can achieve without resorting to tail gas clean-up unit. This criterion is reflected in the sulfur plant investment calculation.

3.5.8 Requirements of Utilities, Catalysts and Chemicals

Typical operating requirements of energy/utilities, broken down into fuel, electricity, steam and cooling water, and of catalysts and chemicals, for each major refinery process unit are shown in Tables 3.5.8.1 and 3.5.8.2 respectively. The data were used to calculate the total and incremental operating energy and material requirements as discussed in Section 6.2.4. Energy export, e.g. net steam generated from sulfur plant, is denoted by a negative sign.

Sources of information are included in notes immediately after each table. Catalyst for sulfur plant is relatively small in quantity, and has a service life of about four years. Therefore, the catalyst cost has been covered by the capital charge which also accounts for the initial charge of catalyst.

TABLE 3.5.8.1

TYPICAL OPERATING REQUIREMENTS OF UTILITIES

PROCESS UNIT	FUEL (5) MBTU/Bbl (MBTU/MSCF)		ELECTRICITY KWh/Bbl (kWh/MSCF) [kWh/ST] {kWh/MLB}		STEAM LB/Bbl (LB/MSCF) [LB/ST] {LB/LB}		COOLING WATER (1) Gal/Bbl (Gal/MSCF) [Gal/ST] {Gal/LB}		
Crude	70 (API 32) 80 (API 40)		0.6		6.75		15		
Vacuum	45 40		0.2		9.75		90		
Reformer	294		3.0		26		900		
Cat Cracker	79		6.0 (4)		-39.0		750		
Naphtha (Naphfining)	32.4		1.20		13.2		10		
Kerosene (Gulfining)	62.2		1.55		11.1		103		
LGO HT	04.0		2.20		- (7)		110		
H-Oil LO HT	84.0		2.20		- (7)		110		
LCO HT	84.0		2.20		- (7)		110		
HCG (Gulfining)	114.2		2.35		- (7)		290		
Vac. Resid (8) (H-Oil)	H	L	H	L	H	L	H	L	
	62	53	14.28	10.845	-53.00	-62.57	38.74	34.36	ATL.
	62	53	13.73	10.845	-53.66	-62.57	41.76	34.36	QUE.
	66	50	9.6	7.8	-37.50	-45.00	58.50	46.80	ONT.
	66	50	9.6	7.8	-37.50	-45.00	58.50	46.80	WEST.
Hydrogen	(237)		(0.70)		NIL		(500)		
Amine	NIL		(2.1) (2)		(30) (3) (6)		(90) (6)		
Sulfur	NIL		[17.86]		[-4,821]		[-4,464]		
SWS	NIL		{0.27}		{0.17}		{0.98}		

NOTES FOR TABLE 3.5.8.1

(1) 20°F Rise.

(2) All pumps are motor driven.

(3) Reboiler heated by steam.

(4) Includes electrical drive for air blower & off-gas compressor.

(5) LHV Basis, Heater Efficiency taken into account.

(6) Assume 10% acid gas.

(7) L.P. Steam consumed will be exceeded by low pressure vent steam. Credit for steam produced not accounted.

(8) Based on 650°F feed temperature.

SOURCES OF DATA: MHG in-house data and references 2, 4, 6, 7 and 9.

TABLE 3.5.8.2

UNIT REQUIREMENTS OF CATALYSTS AND CHEMICALS

PROCESS UNIT	CATALYST REPLACEMENT (Lb/Bbl of Feed)			
Reformer	0.004			
Catalytic Cracker (Zeolite)	0.2			
Naphtha HT	0.002			
Kerosene HT	0.002			
LGO HT	0.0025			
LCO HT	0.003			
HCO HT	0.005			
H-Oil ($/Bbl)				
	Atlantic	Quebec	Ontario	Western
90 V% Conv.	0.81	0.81	0.661	0.661
66 V% Conv.	0.71	0.71	0.398	0.398
	CHEMICAL REPLACEMENT			
Crude (Desalter)				
Caustic	0.001 Lb/Bbl of Feed			
Demulsifier	0.001 Lb/Bbl of Feed			
Amine	3 Lb/MMSCF of Feed			

SOURCES: MHG in-house data and references 2, 5.

4.0 OPERATING COST BASIS

For comparison purposes, the annual operating costs of all cases are to be calculated to account for the variation of:-

1. Annual capital charge
2. Fixed operating costs which include costs of:-
    - operating personnel
    - maintenance
    - general, sales, administration, taxes and insurance.
3. Variable operating costs which include costs of:-
    - crude feed
    - products
    - operating energy/utilities
    - catalysts and chemicals.

Basis of calculation and cost estimates are described in the following sections.

4.1 Annual Capital Charges

The annual capital charge was bsed on 25% of total investment cost as given in the scope of the study.

4.2 Fixed Operating Costs

(a) Operating Personnel

An average salary of $37,460 per year was used to cover the manpower cost of combined operating and supervisory personnel. The cost figure was based on StatsCan's survey of Canada's average wage including fringe benefits in petroleum and natural gas industry for the month of July 1982. Estimates of manpower for different process units are described in Section 4.4.

(b) Maintenance

Annual Maintenance Charge was based on 3% of the total capital cost to cover both material and labour requirements as stated in the scope of the study.

(c) General, Sales, Administration, Taxes and Insurance

The annual costs for general, sales, administration, taxes and insurance were based on 3.5% of the total capital cost as stated in the scope of the study.

4.3 Variable Operating Costs

Unit prices of feed, products, utilities, catalysts and chemicals which are variables in the study cases are summarized in Table 4.3.1, and the basis is described below.

(a) Crude

Crude prices in Canada varied from region to region and involved computation of taxes and petroleum compensation charges. To calculate the annual operating costs, the average crude price of $34/Bbl for mid 1981 and other values given in Scope were used for all regions.

(b) Fuel gas, Hydrogen, Naphtha, Heavy Fuel Oil and Vacuum Resid

Costs of fuel gas products were calculated based on the costs of natural gas with equivalent heating values. The prices of natural gas in July 1982 were as reported in Energy Statistics Handbook. For Atlantic region where natural gas was not available, costs of fuel gas were based on the price of HFO with equivalent heating value. Naphtha price was assumed to be 125% of the average crude oil price which was estimated to be $37.8/Bbl in mid 1982.

Prices of heavy fuel oil were obtained from EMR and other publications (26, 29). The prices of HFO were only used to develop costs of steam. Price of vacuum resid was backed out from the average price of HFO and LFO, assuming vacuum resid was blended with LFO to make HFO. Application of the prices of HFO and vacuum resid are discussed in Chapters 6 & 7.

(c) Sulfur

Prices of sulfur were extracted from December, 1982 issue of Corpus Chemical Report (10).

(d) Electric Power, Steam and Cooling Water

Rates of electricity are based on supply of more than 100 MW to an industrial user in each region (25). Steam costs were developed based on using heavy fuel oil as fuel. In most of the study cases, there are increases in steam production relative to the reference base case due to the addition of steam producing process units. The initial costs for these incremental steam production have already been accounted for by the investments for process units. It is therefore simpler to exclude capital charge from the steam costs in the operating cost calculation. The cost of cooling water however does include capital charge.

(e) Catalysts and Chemicals

The prices of amine, caustic and demulsifier were extracted from December, 1982 issue of Corpus Chemical Report (10). The prices of catalysts were obtained from Engelhard Industries of Canada Ltd. and in-house data files. Catalyst requirements for H-Oil process were only available in expense per barrel of feed which have been included in Table 3.5.8.2; the catalyst consumption rate and price are proprietary information of the process licensor.

TABLE 4.7.1

OPERATING COSTS BASIS

1. ANNUAL CAPITAL CHARGE: 25% on Investment

2. FIXED OPERATING COSTS:

- Operating/Supervisory Personnel	37,460/yr./man
- Maintenance	3% of Capital Charge
- General, Sales, Administration, Taxes & Insurance	3.5% of Capital Charge

3. VARIABLE OPERATING COSTS:

		ATL.	QUE.	ONT.	WEST.
- Crude	$/Bbl		Average $34		1981 Costs
			Average $37.80		1982 Costs
- Electrical Power	c/KWH	3.70	2.15	2.88	2.2
- Heavy Fuel Oil	$/Bbl	31.92	32.89	32.36	31.30
- Natural Gas	$/1000 SCF	-	4.68	3.96	2.97
- Naphtha	$/Bbl		Average $47.25		1982 Costs
- Sulfur			Average $85/LT		
- Vacuum resid/pitch	$/Bbl		Average $23/Bbl		

4. CATALYSTS AND CHEMICALS

- Amine (DEA)	$66.8/100 lb.
- Caustic Soda	$33.2/100 lb.
- Demulsifier	Approx. $82/100 lb.
- Reformer Catalyst	$18/lb.
- Cat Cracker Catalyst (Zeolite)	15c/Bbl Feed
- HDS Catalyst	$5.05/lb.
- H_2 Plant Catalyst	0.178c/lb. of H_2

4.4 Operating Manpower Requirements

The manpower required for different additional process units to cover a 24 hour operation was estimated to be as follows:

PROCESS UNIT	OPERATORS (4 shifts)	SUPERVISORS	TOTAL
Amine	4	½	4.5
Sulfur	8	1	9
Sour Water Stripper	2	½	2.5
Hydrogen	8	1	9
H-Oil	12	1	13
Kerosene Hydrotreater	8	1	9

It was assumed that new manpower requirements are independent of the new process unit capacities most of which are relatively small in this study. Since allowances for maintenance and general, sales and administration have been made in the fixed operating costs as prescribed in the Scope, the related manpower was not included in the above estimate.

5.0 CAPITAL COST BASIS

5.1 General

The estimate includes all fixed capital plant costs but excludes land acquisition costs.

Plant costs include:-

- Battery Limit Process Unit Costs
- Construction Costs
- Home Office Costs.
- Related Off-site Costs

5.2 Basis

The capital investment costs are based on a continuously updated extensive cost library and additional data obtained from licensors.

5.2.1 Within Battery Limits

The plant costs include all direct and indirect costs necessary to engineer, procure and construct a battery limit plant on a site with normal ground conditions.

Included in the battery limit plant are the equipment components, the cost of major process items such as towers, reactors, exchangers, etc. The material components including all necessary items for piping, instrumentation, civil, structural steel, electrical, insulation and painting work. The labour component is comprised of the direct field cost of installing the aforementioned equipment and material. The associated indirect costs include items such as labour fringe benefits, unallocable labour, small tools and consumables, construction equipment, temporary construction facilities and field supervision. The battery limit plant cost includes all related Home Office costs such as engineering, procurement, services and administration.

5.2.2 Related Offsites

The related offsites include such items as:-

- Site development and improvement, roads and carparks, lighting, fencing, etc.
- Instrument control tie-ins
- Industrial buildings, additional space in administration building, warehouses, etc.
- The connections to power supply
- Process and services piping to serve the unit.

These additions would normally be estimated on an individual refinery basis as each facility is unique in nature. As it is not practical to carry out an individual estimate, a general allowance based on a proportion of plant costs has been made and indicated graphically.

5.3 Basis of Graphs

The graphs are produced to indicate the capital costs for each type of process unit within its battery limit. The related offsites required to connect the new unit to the existing refinery is also inidcated on the graph. To arrive at the total costs, the costs within Battery Limits and the Related Offsites are to be added together.

For a more detailed explanation of specific inclusions etc. for within "Battery Limits" and "Related Offsites", see Sections 5.2.1 and 5.2.2.

5.4 Regional Cost Variations

The assessment of the cost implications according to location uses Ontario as the basis (i.e. Value 1.0). The regional conversion **factors tabulated** in Section 5.4.1 are to be applied to the capital cost graphs in order to adjust for construction in regions other than Ontario.

In arriving at these factors, previous project experiences, and statistics were analysed in detail for implications in the areas of Engineering, Procurment and Construction. The engineering salaries and costs, major equipment, bulk materials, construction labour costs and productivity were reviewed for each specific region in order to establish meaningful adjustment factors.

5.4.1 Regional Conversion Factors

The factors to be applied to the various regions are as follows:-

REGION	REGIONAL CONVERSION FACTOR
Ontario	1.000
Quebec	1.013
Atlantic	1.033
Western (Excluding B.C.)	1.024
Western B.C.	1.091

5.5 Costs Related to Small Increases in Throughput

It is realized that in some instances the most economic means of obtaining small increases in throughput would be to debottleneck the unit. However, it is not practical, or within the scope of this study to consider the cost implications associated with this approach. The increases in cost are therefore established as follows:-

1. However small the increases in throughput, these are considered to require a new unit.
2. The new unit cost is that of the smallest practical unit for the type of plant, see applicable graph.

5.6 Plant Capital Costs

The individual plant capital costs are shown in the following graphs:-

Figure 5.4.1	Sour Water Stripper
" 5.4.2	Sulfur including Tail Gas Clean-up
" 5.4.3	Amine
" 5.4.4	Hydrogen
" 5.4.5	H-Oil - Western & Ontario Feed
" 5.4.6	H-Oil - Quebec & Atlantic Feed
" 5.4.7	Gas Oil Hydrotreater
" 5.4.8	Naphtha Hydrotreater
" 5.4.9	Kerosene Hydrotreater

5.7 Escalation of Costs

The cost basis contained in this report is based on construction in Mid-1982 in the Ontario Region. To arrive at costs for construction in subsequent years, references to the graphs shall be adjusted by means of applying the Nelson Refinery (Inflation) Index.

5.7.1 Description of Nelson Index

The basic concept of a refinery construction cost index was developed in the year immediately following World War II. The Nelson Index reached the first published form in December 1949. Several minor modifications have been made since that time, to adjust for changing proportions in costs of various items of equipment and that of labour.

The Nelson Index is now the accepted industry standard for cost determination and comparisons. Basically, it is an inflation index, and as such it shows the relative cost of duplicating an installation at rates other than the hase case of 1946, without respect to change in mechanical or process design, construction techniques or size.

The values of the Nelson Refinery (Inflation) Index are published in the first issue of the Oil and Gas Journal each month. More detailed tabulations are published in this periodical, apparently in the first issues of January, April, July and October.

For additional information on the Nelson Cost Index, see publications listed in reference section 8.0 (6, 11).

MID-YEAR '82, ONTARIO BASE

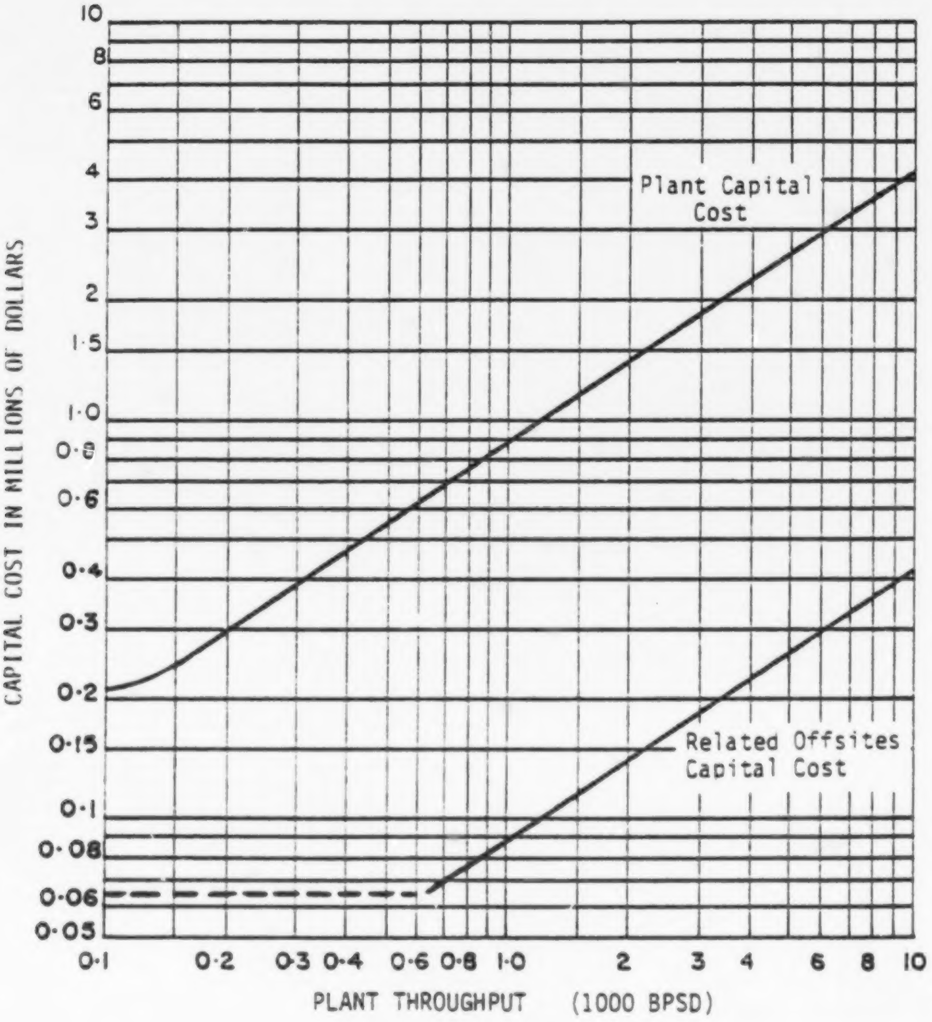


FIG. 5.4.1 CAPITAL COSTS FOR SOUR WATER STRIPPER PLANTS

MID-YEAR '82, ONTARIO BASE

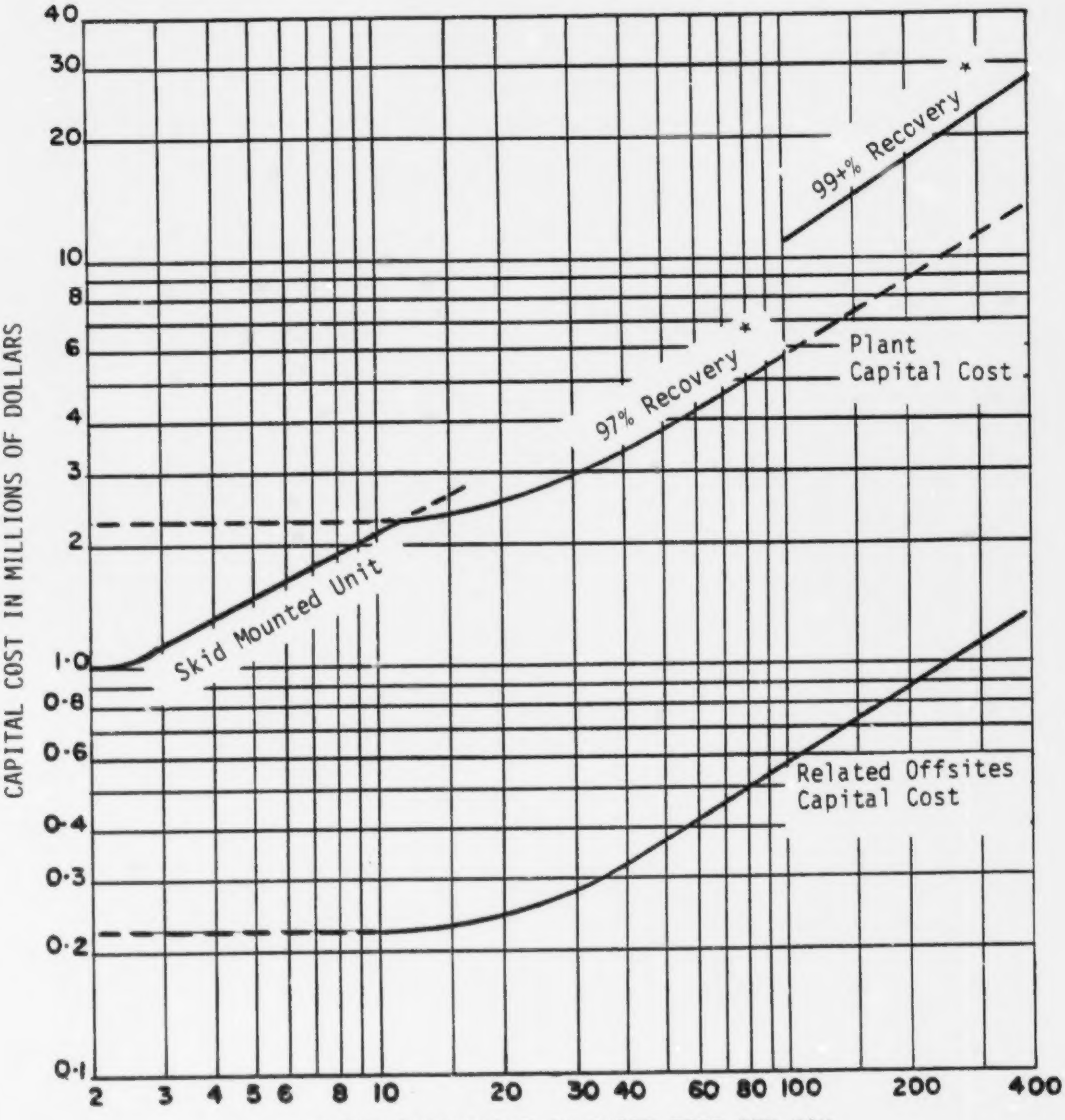


FIG. 5.4.2 CAPITAL COSTS FOR SULFUR PLANTS

* If tail gas units required, costs included.

MID-YEAR '82, ONTARIO BASE

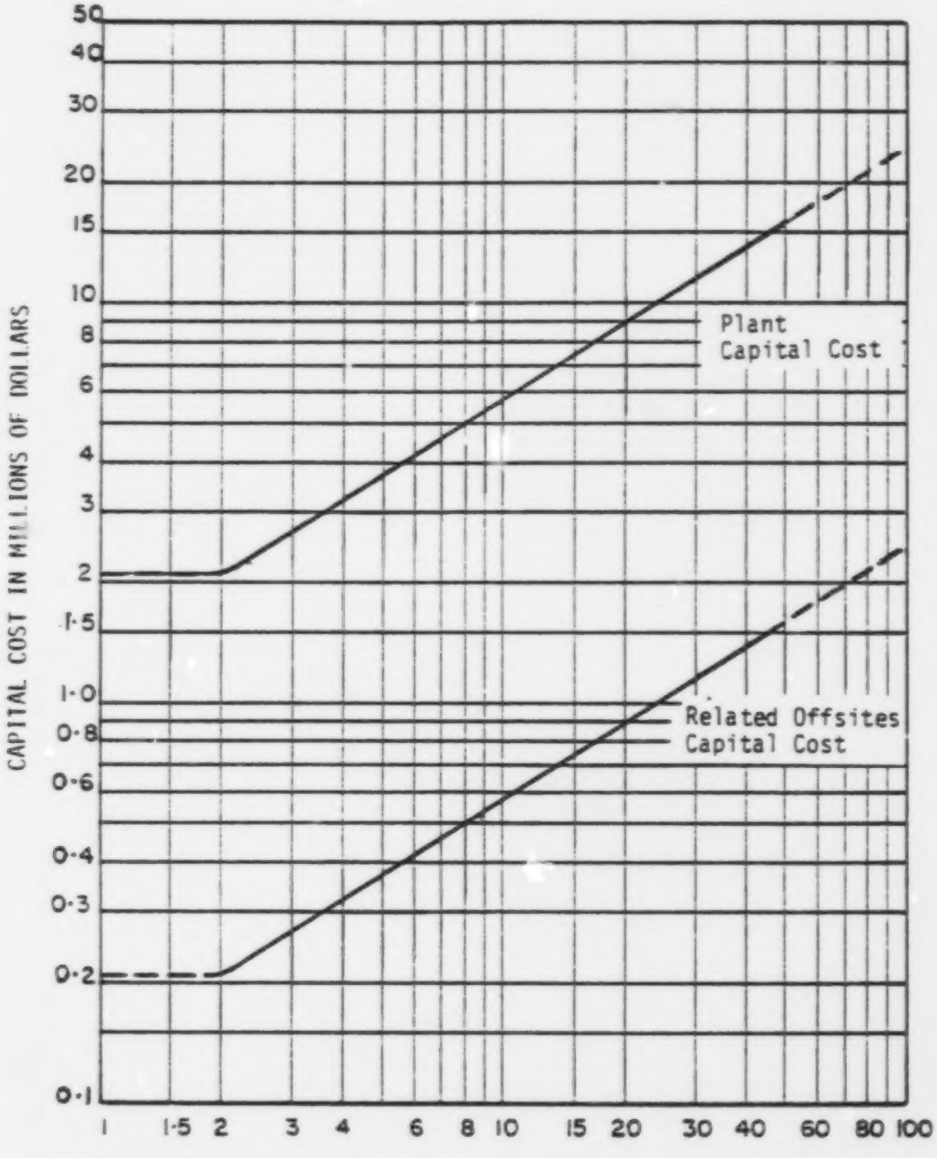


FIG. 5.4.3 CAPITAL COSTS FOR AMINE PLANTS
(H_2S CONTENT APPROX. 19%)

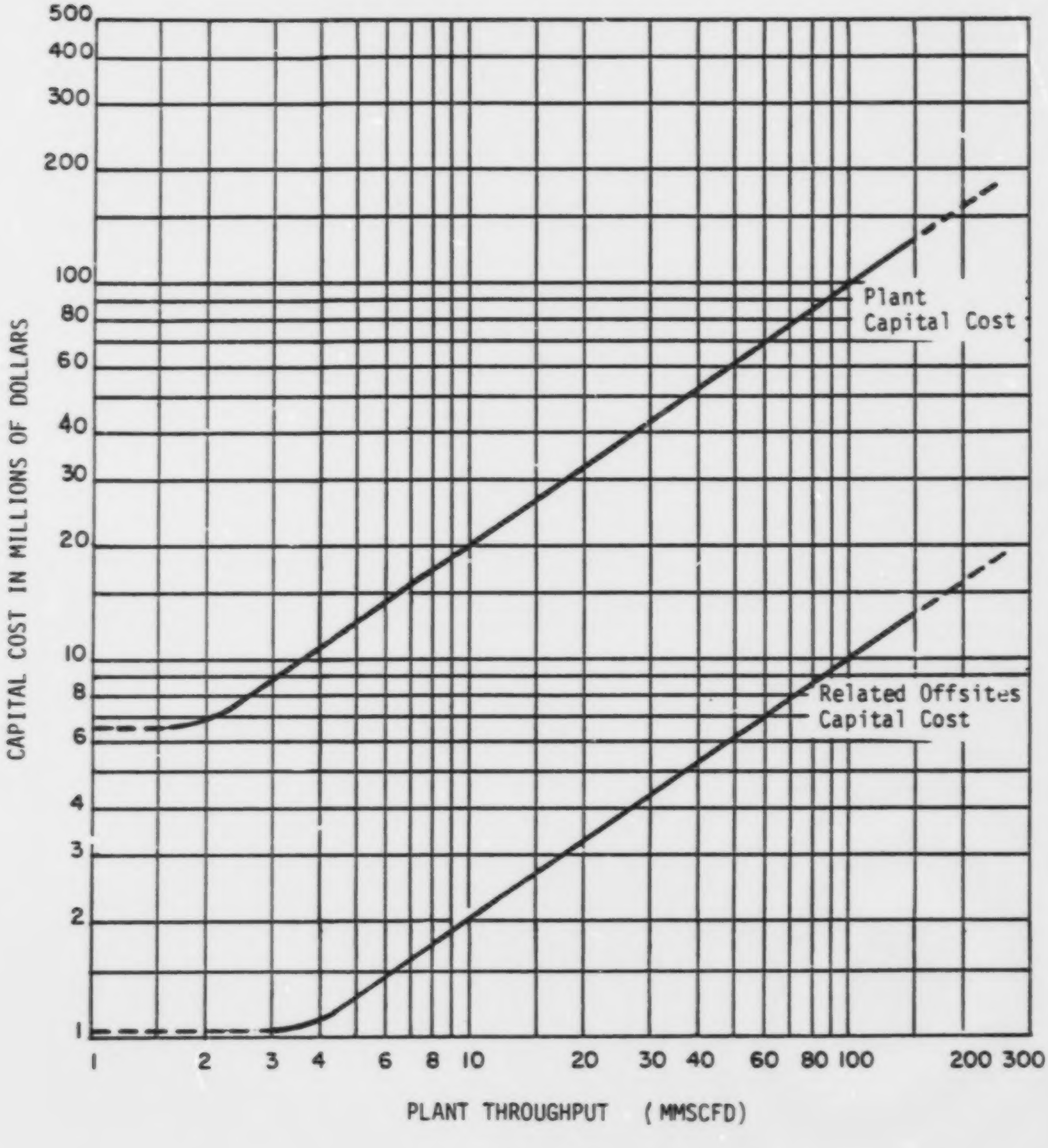


FIG. 5.4.4 CAPITAL COSTS FOR HYDROGEN PLANTS

MID-YEAR '82, ONTARIO BASE

Based on Vacuum Resid Feed from Western Region; also applicable to Vacuum Resid from Ontario Region.

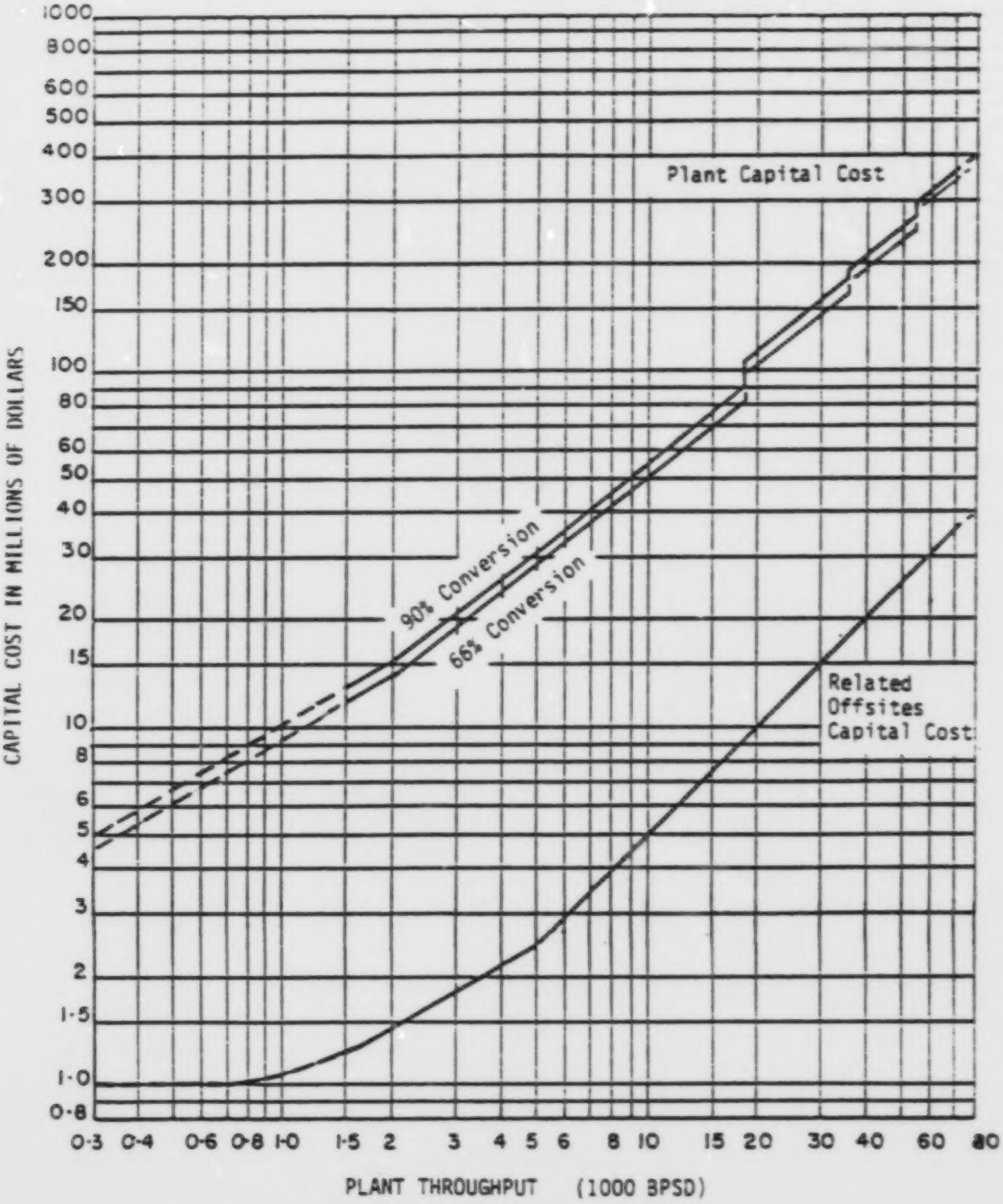


FIG. 5.4.5 CAPITAL COSTS FOR H-OIL PLANTS

MID-YEAR '82, ONTARIO BASE

Based on Vacuum Feed from Quebec region; also applicable to Vacuum Feed from Atlantic Region.

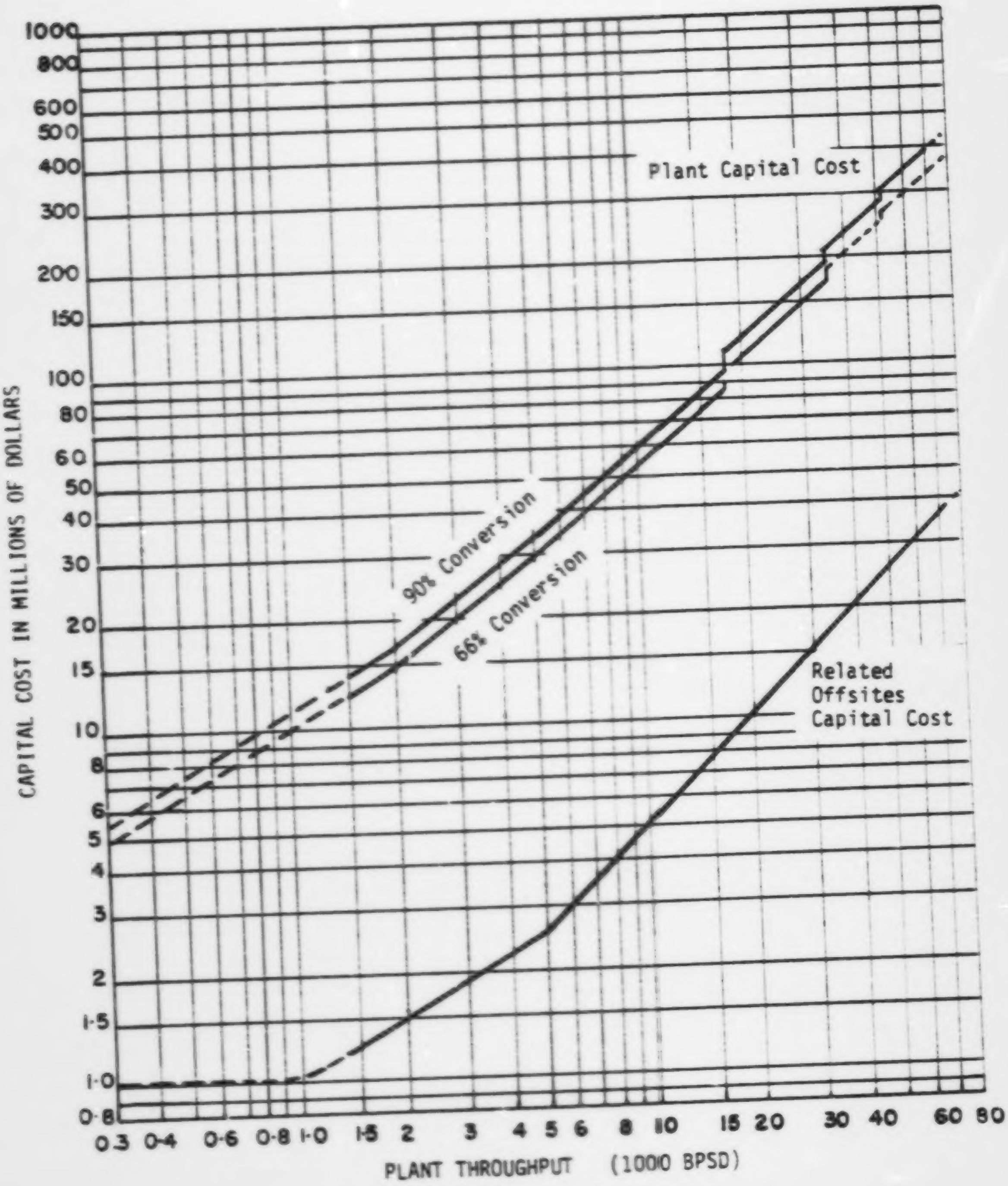


FIG. 5.4.6 CAPITAL COSTS FOR H-OIL PLANTS

MID-YEAR '82, ONTARIO BASE

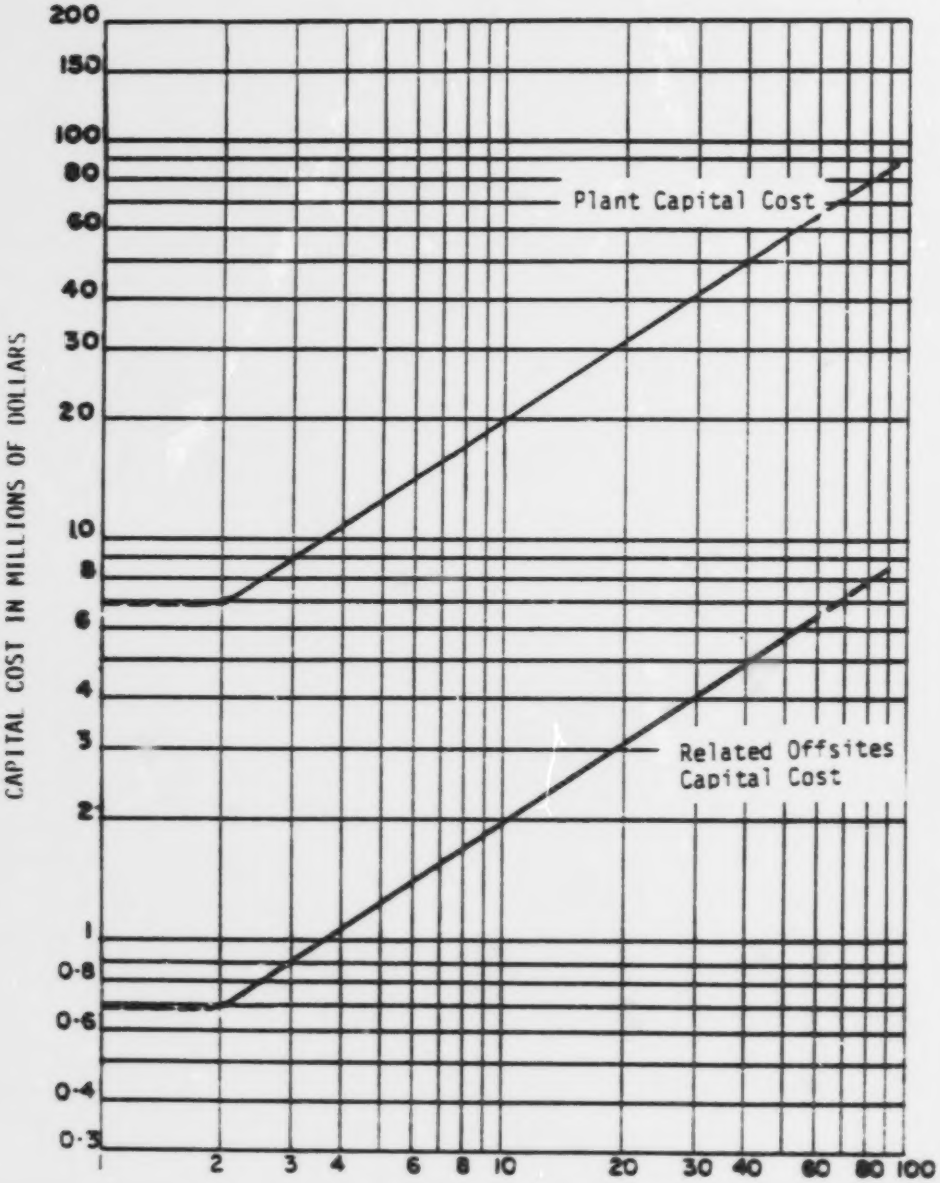


FIG. 5.4.7 CAPITAL COSTS FOR GAS OIL HYDROTREATER PLANTS

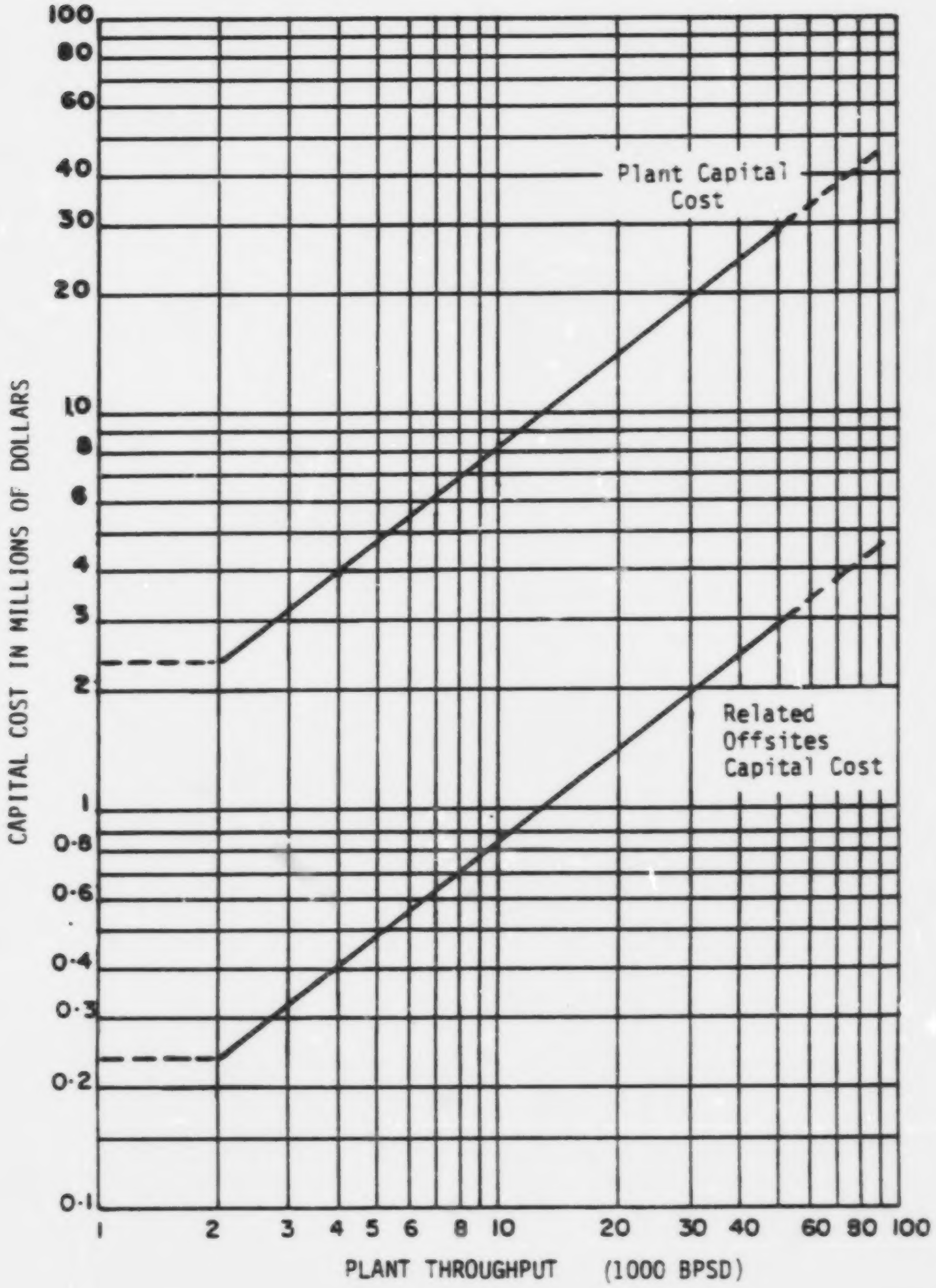


FIG. 5.4.8 CAPITAL COSTS FOR NAPHTHA HYDROTREATER PLANTS

MID-YEAR '82, ONTARIO BASE

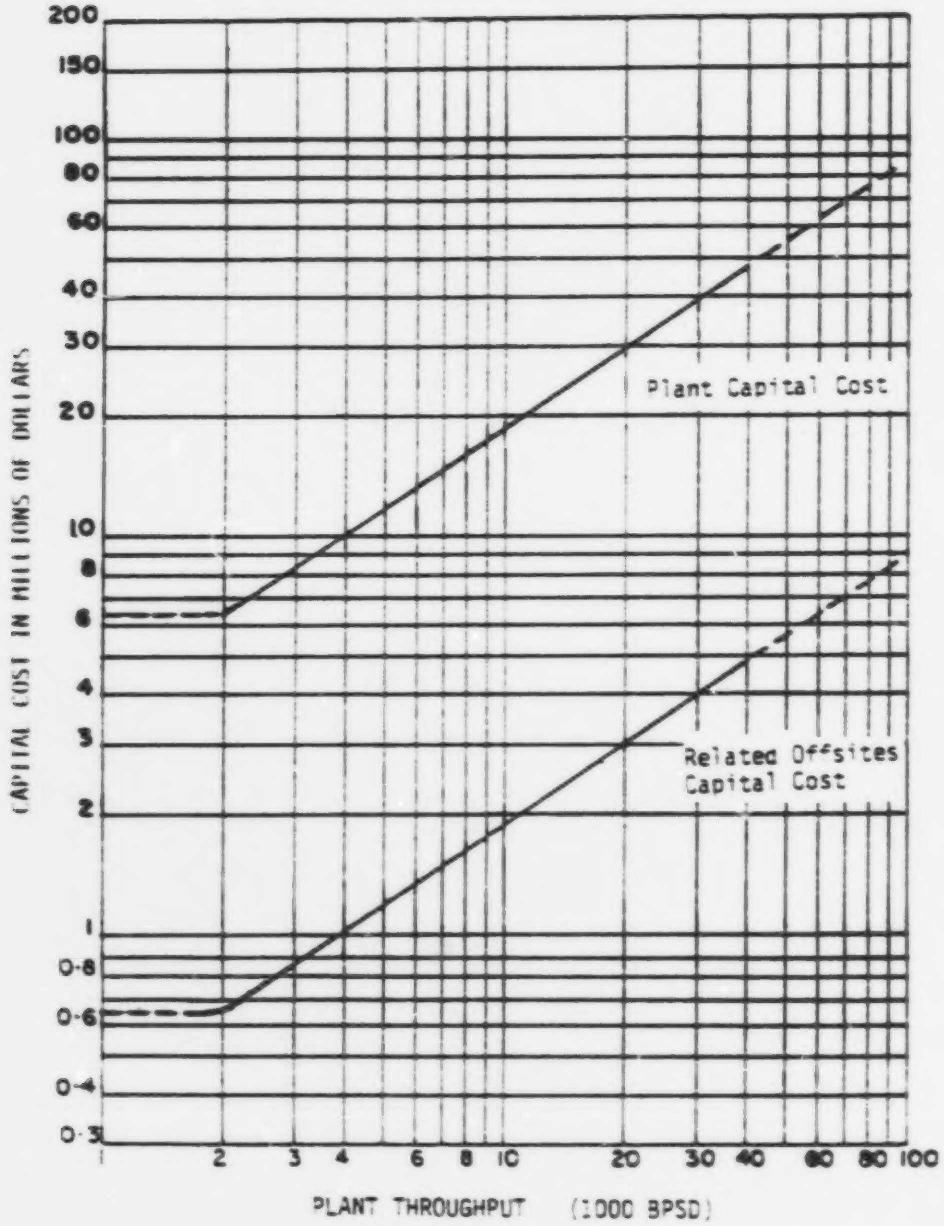


FIG. 5.4.9 CAPITAL COSTS FOR KEROSENE HYDROTREATER PLANTS

6.0 SIMULATION RESULTS AND DISCUSSION

6.1 Base Case

The purpose of the base case is to provide a reasonable and consistent reference to which the study cases can be compared. The basis of feeds, product slates and product qualities have been described in Section 3.5.1 and 2. Since not all actual product qualities were known, it was assumed that they were slightly better than the government specifications for the petroleum products in year 1981. The lead contents of gasoline used in simulation do not exactly match the actual usage to that year. Fine tunning in this instance was not done because the impact on the result was insignificant. Optimizations of hydrotreater throughputs however were carried out to arrive at the sulfur content in products consistent with the study basis. The optimized cases are referred to as the "reference base cases" (Case BR) to which the study cases will be compared. The results of the reference base cases are included in Appendix VI.

It was found that the 1981 refinery operation of the four regions described in Chapter 3 can be successfully simulated. The simulated crude rates for all regions are about two percent higher than the rates reported by Statistics Canada except for Western region which is four percent higher. Considering the completeness of the data, the agreement is good and certainly acceptable for the purposes of this study.

The simulated reference base cases indicate that the utilizations of the installed capacities of major process units such as crude, vacuum and catalytic cracking were higher in Western region as expected (Tables 6.2.3.1 to 4). Utilization of the hydrotreating capacities however were higher in Atlantic and Quebec regions, probably due to the higher sulfur crude diets consumed in these regions (Tables 6.2.3.5 to 8). The available flexibility in the hydrotreating capacities understandably will have influence on the abilities of the refineries to achieve the objective of reducing sulfur in the products. As discussed earlier, the hydrotreater throughputs in the reference base cases and in all other study cases have been optimized to ensure they are on a consistent basis for comparison.

6.2 Study Cases

The print-outs of computer simulations of all study cases are included in Appendix VI. The print-outs of each case are divided into Part I, which contains the results from the computer model simulation and Part II, which contains the results of mass balance adjustment due to the inclusion and optimization of hydrotreaters, and the utility data handling.

The pertinent data from the simulations were tabulated for comparison in this chapter. The tables were developed for each topic of discussion for all regions and the topics are arranged according to the sequence of calculations and cost data development.

The results are presented for comparison purposes. For Cases 1 and 2, the product slates are the same as the reference base cases. For Cases 3 to 6 in which H-Oil process units were added, the product slates are no longer consistent with the reference base cases. In the absence of an acceptable pricing basis for all the products and a defined policy on fuel substitution, which is beyond the scope and intent of this study, no definite conclusions can be drawn here regarding the relative merit of the study cases. Nevertheless, the impact of imposing different sulfur limits on the petroleum products of the composite refineries in each region and the potential of crude reductions and sulfur reductions by adding the ebullated-bed hydrocracking processes to the composite refineries are well demonstrated by these simulation results.

6.2.1 Annual Sulfur Reductions in Products

Among the petroleum fuel products, the major proportion of sulfur emissions are contributed by HFO, LFO, diesel fuel oil and kerosene/stove oil. According to Scope, these four categories of products were divided into "Refinery's Own Consumption" and "Saleable Products" for sulfur reduction comparison between cases. The "Own Consumption" figures of these products were as reported in the publication of Statistics Canada (3) from which the product slate basis was derived.

The "Saleable Products" of HFO, LFO, diesel fuel oil, kerosene/stove oil (including import/export and interprovincial transfer) were calculated from the simulated net productions and the reported "Own Consumption" by subtraction, taking into account the small amount of stock and losses as reported if necessary. The rates of LFO, diesel and kersone/stove oil were maintained constant for all cases. However, since the HFO production were reduced in Cases 3 to 6 where H-Oil units were added, the HFO rates for these cases are not consistent with the reference base cases. For sulfur reduction calculation, the HFO was allocated to "Own Consumption" prior to "Saleable Products". Background on the basis of HFO production for Cases 3 to 6 are described in Section 6.2.2.2. The "Refinery's Own Consumption" and "Saleable Products" of fuel oil products calculated on this basis are summarized in Tables 6.2.1.5 to 8 for the four regions. Vacuum resid and pitch from the H-Oil units which were allocated to coke and asphalt products are also included in these tables to indicate their shares of sulfur. Sulfur content of these products are lower than the original vacuum resid due to desulfurization by the H-Oil process. HFO products are substantially less for cases with H-Oil process as expected.

The sulfur contents of HFO, LFO, diesel and kerosene/stove oil are mostly the same as those of the reference base cases. In some instances, the sulfur contents of HFO were better than the reference base cases even without hydrotreating because the sulfur contents of the blending stocks were already low. The sulfur contents of fuel oil products and vacuum resids are summarized in Tables 6.2.1.1 to 4 for the four regions.

The sulfur reductions as a result of different limits of sulfur contents imposed on the fuel oil products are presented in Tables 6.2.1.9 to 12 and discussed below. Some small negative reductions are due to the effect of specific gravity variations.

(a) Sulfur reduction in LFO and lighter products -

There is no sulfur reduction for Cases 1, 3 and 5 for the Ontario region which already met the objective of 0.3 wt% sulfur in LFO and lighter products in 1981. For the other three regions the reductions of sulfur in these products by imposing 0.3 wt% sulfur limit are not significant. The annual reductions are approximately 3,000 tonnes for Atlantic, 2,000 tonnes for Quebec and 800 tonnes for Western regions.

The annual reductions of sulfur in these products by imposing 0.1 wt% sulfur limit are significantly higher. They are approximately 10,000 tonnes for Atlantic, 15,000 tonnes for Quebec, 11,000 tonnes for Ontario and 7,000 tonnes for Western regions.

(b) Sulfur reduction in all fuel oil products -

In Cases 1 and 2, because the sulfur contents of HFO have been maintained at the same level as the reference base case, it is no surprise that the HFO does not have significant contribution to sulfur reduction. However, as a result of reduction of HFO production due to the addition of H-Oil process there are substantial reductions of sulfur in other cases. The total sulfur reductions in Cases 3 to 6 (not including the sulfur reduction in vacuum resid products) are several times the magnitude of the sulfur reductions in LFO and lighter products. The impact of adding H-Oil units on sulfur reduction appears to be greater for the eastern regions which have greater reduction in HFO production. The sulfur reduction through HFO product reduction is realistic if alternative sulfur-free fuel such as natural gas can be used to replace HFO. Additional investment would naturally be required for the fuel conversion.

TABLE 6.2.1.1

SULFUR CONTENT OF FUEL OIL AND VACUUM RESID

ATLANTIC REGION

CASE	SULFUR WT. %	REFINERY'S OWN CONSUMPTION				SALEABLE PRODUCTS				VAC. RESID OR H-OIL PITCH
		HFO	LFO	DIESEL	KEROSENE/ STOVE	HFO	LFO	DIESEL	KEROSENE/ STOVE	
A	1981 ● ACTUAL	1.903 (1)	0.389	0.358	0.145	2.610	0.389	0.358	0.145	3.433
0	SIMULATED BASE	2.754	0.390	0.359	0.146	2.754	0.390	0.359	0.146	3.574
BR	BASE REF.	2.754	0.390	0.359	0.146	2.754	0.390	0.359	0.146	3.574
1	LFO - 0.3	2.753	0.300	0.300	0.130	2.753	0.300	0.300	0.130	3.574
2	LFO - 0.1	2.752	0.100	0.100	0.100	2.752	0.100	0.100	0.100	3.574
3	LFO - 0.3 H-OIL LOW CONV.	2.258 **	0.300	0.300	0.130	2.258 **	0.300	0.300	0.130	1.830
4	LFO - 0.1 H-OIL LOW CONV.	2.257 **	0.100	0.100	0.100	2.257 **	0.100	0.100	0.100	1.830
5	LFO - 0.3 H-OIL HIGH CONV.	2.754	0.300	0.300	0.130	2.754	0.300	0.300	0.130	2.110
6	LFO - 0.1 H-OIL HIGH CONV.	2.754	0.101	0.097	0.100	2.754	0.101	0.097	0.100	2.110

NOTES:

● Based on incomplete data from Air Pollution Control Directorate, Environment Canada, Dec. 1981.

** Calculated S wt% of HFO blended with pitch

Atlantic - S (HFO) = 2.754%
Quebec - S (HFO) = 2.281%

△ Calculated S wt% of HFO blended with pitch
S (HFO) = 1.347%

△△ Calculated S wt% of HFO blended with pitch
S (HFO) = 1.346%

(1) Calculated from ● including "Own AGO".

(2) No data available from ●.

TABLE 6.2.1.2

SULFUR CONTENT OF FUEL OIL AND VACUUM RESID

QUEBEC REGION

CASE \ SULFUR WT. %		REFINERY'S OWN CONSUMPTION				SALEABLE PRODUCTS				VAC. RESID OR H-OIL PITCH
		HFO	LFO	DIESEL	KEROSENE/ STOVE	HFO	LFO	DIESEL	KEROSENE/ STOVE	
A	1981 ● ACTUAL	2.171	0.338	0.323	0.186	2.328	0.338	0.323	0.186	NOT AVAILABLE (2)
B	SIMULATED BASE	2.282	0.338	0.323	0.186	2.282	0.338	0.323	0.186	3.084
BR	BASE REF.	2.282	0.338	0.323	0.186	2.282	0.338	0.323	0.186	3.084
1	LFO - 0.3	2.280	0.300	0.300	0.130	2.280	0.300	0.300	0.130	3.084
2	LFO - 0.1	2.280	0.100	0.100	0.100	2.280	0.100	0.100	0.100	3.084
3	LFO - 0.3 H-OIL LOW CONV.	2.132 **	0.300	0.300	0.130	2.132 **	0.300	0.300	0.130	1.580
4	LFO - 0.1 H-OIL LOW CONV.	2.132 **	0.100	0.099	0.100	2.132 **	0.100	0.099	0.100	1.580
5	LFO - 0.3 H-OIL HIGH CONV.	2.282	0.299	0.300	0.130	2.282	0.299	0.300	0.130	1.920
6	LFO - 0.1 H-OIL HIGH CONV.	2.281	0.101	0.100	0.100	2.281	0.101	0.100	0.100	1.920

NOTES:

● Based on incomplete data from APCD, Environment Canada, Dec. 1981.

** Calculated S wt% of HFO blended with pitch

Altantic - S (HFO) = 2.754%
Quebec - S (HFO) = 2.281%

△ Calculated S wt% of HFO blended with pitch
S (HFO) = 1.347%

△△ Calculated S wt% of HFO blended with pitch
S (HFO) = 1.346%

(1) Calculated from ● including "Own AGO".

(2) No data available from ●.

TABLE 6.2.1.3

SULFUR CONTENT OF FUEL OIL AND VACUUM RESID

ONTARIO REGION

CASE \ SULFUR WT. %		REFINERY'S OWN CONSUMPTION				SALEABLE PRODUCTS				VAC. RESID OR H-OIL PITCH
		HFO	LFO	DIESEL	KEROSENE/ STOVE	HFO	LFO	DIESEL	KEROSENE/ STOVE	
A	1981 ● ACTUAL	1.435 Δ	0.287	0.270	0.084	1.064	0.287	0.270	0.084	2.238
B	SIMULATED BASE	1.646	0.287	0.272	0.084	1.646	0.287	0.272	0.084	2.232
BR	BASE REF.	1.646	0.287	0.272	0.084	1.646	0.287	0.272	0.084	2.232
1	LFO - 0.3	1.646	0.287	0.272	0.084	1.646	0.287	0.272	0.084	2.232
2	LFO - 0.1	1.646	0.100	0.100	0.084	1.646	0.100	0.100	0.084	2.232
3	LFO - 0.3 H-OIL LOW CONV.	1.352 Δ	0.287	0.272	0.084	1.352 Δ	0.287	0.272	0.084	1.380
4	LFO - 0.1 H-OIL LOW CONV.	1.351 ΔΔ	0.100	0.100	0.084	1.351 ΔΔ	0.100	0.100	0.084	1.380
5	LFO - 0.3 H-OIL HIGH CONV.	1.411	0.287	0.272	0.084	1.411	0.287	0.272	0.084	1.380
6	LFO - 0.1 H-OIL HIGH CONV.	1.410	0.100	0.100	0.084	1.410	0.100	0.100	0.084	1.380

NOTES:

● Based on incomplete data from APCD, Environment Canada, Dec. 1981.

** Calculated S wt% of HFO blended with pitch

Altantic - S (HFO) = 2.754%
Quebec - S (HFO) = 2.281%

Δ Calculated S wt% of HFO blended with pitch
S (HFO) = 1.347%

ΔΔ Calculated S wt% of HFO blended with pitch
S (HFO) = 1.346%

(1) Calculated from ● including "Own AGO".

(2) No data available from ●.

TABLE 6.2.1.4

SULFUR CONTENT OF FUEL OIL AND VACUUM RESID

WESTERN REGION

CASE \ SULFUR WT. %		REFINERY'S OWN CONSUMPTION				SALEABLE PRODUCTS				VAC. RESID OR H-OIL PITCH
		HFO	LFO	DIESEL	KEROSENE/ STOVE	HFO	LFO	DIESEL	KEROSENE/ STOVE	
A	1981 ● ACTUAL	0.856 (1)	0.376	0.165	0.095	1.050	0.376	0.165	0.095	NOT (2) AVAILABLE
B	SIMULATED BASE	1.395	0.376	0.165	0.095	1.395	0.376	0.165	0.095	2.224
BR	BASE REF.	1.395	0.376	0.165	0.095	1.395	0.376	0.165	0.095	2.224
1	LFO - 0.3	1.392	0.300	0.165	0.095	1.392	0.300	0.165	0.095	2.224
2	LFO - 0.1	1.386	0.100	0.100	0.095	1.386	0.100	0.100	0.095	2.224
3	LFO - 0.3 H-OIL LOW CONV.	1.260	0.300	0.165	0.095	1.260	0.300	0.165	0.095	1.230
4	LFO - 0.1 H-OIL LOW CONV.	1.260	0.100	0.101	0.095	1.260	0.100	0.101	0.095	1.230
5	LFO - 0.3 H-OIL HIGH CONV.	1.268	0.300	0.165	0.095	1.268	0.300	0.165	0.095	1.230
6	LFO - 0.1 H-OIL HIGH CONV.	1.268	0.100	0.101	0.095	1.268	0.100	0.101	0.095	1.230

NOTES:

● Based on incomplete data from APCD, Environment Canada, Dec. 1981.

** Calculated S wt% of HFO blended with pitch

Altantic - S (HFO) = 2.754%
Quebec - S (HFO) = 2.281%

△ Calculated S wt% of HFO blended with pitch
S (HFO) = 1.347%

△△ Calculated S wt% of HFO blended with pitch
S (HFO) = 1.346%

(1) Calculated from ● including "Own AGO".

(2) No data available from ●.

TABLE 6.2.1.5

REFINERY'S OWN FUEL CONSUMPTION, SALEABLE FUEL OIL AND VACUUM RESID

ATLANTIC REGION

	CASE	ANNUAL FLOWRATE	REFINERY'S OWN CONSUMPTION				SALEABLE PRODUCTS **				VAC. RESID OR PITCH PRODUCT
			HFO	LFO	DIESEL	KERO/STOVE	HFO	LFO	DIESEL	KERO/STOVE	
B	SIMULATED	* m^3/y	183 823	3 679	10 058	1 193	2 732 658	3 293 085	931 795	226 490	359 150
&	BASE CASE &	BPCD	3 168	63	173	21	47 090	56 748	16 057	3 903	6 189
BR	BASE REF CASE	s.g.	1.0094	0.8455	0.8275	0.8002	1.0094	0.8455	0.8275	0.8002	1.0403
1	LFO - 0.3	m^3/y									
		BPCD				SAME	AS BASE	AND			
		s.g.									
2	LFO - 0.1	m^3/y				BASE	REF. CASES				
		BPCD									
		s.g.									
3	LFO - 0.3	m^3/y	(2) 183 823	3 679	10 058	1 193	(1)(2) 395 477	3 293 085	931 795	226 490	359 150
	H-OIL:	BPCD	(2) 3 168	63	173	21	(1)(2) 6 815	56 748	16 057	3 903	6 189
	LOW CONV.	s.g.	(3) 1.0318	0.8559	0.8408	0.8000	(3) 1.0318	0.8559	0.8408	0.8008	1.0430
4	LFO - 0.1	m^3/y									
	H-OIL:	BPCD				SAME	AS CASE	NO. 3			
	LOW CONV.	s.g.									
5	LFO - 0.3	m^3/y	183 823	3 679	10 058	1 193	(1) 73 185	3 293 085	931 795	226 490	(4) 188 076
	H-OIL:	BPCD	3 168	63	173	21	(1) 1 272	56 748	16 057	3 903	(4) 3 241
	HIGH CONV.	s.g.	1.0333	0.8579	0.8450	0.8005	1.0333	0.8579	0.8450	0.8005	1.1150
6	LFO - 0.1	m^3/y									
	H-OIL:	BPCD				SAME	AS CASE	NO. 6			
	HIGH CONV.	s.g.									

NOTES:

* Based on Statistics Canada publication: Refined Petroleum Products, Dec. 1981.
Assuming consumption remains the same for all cases in Atlantic and Ontario Regions.

** Calculated from *. For Cases B, BR, 1 & 2 Saleable Product = Net Production + Stock - Losses - Own Consumption.

(1) HFO available for sales less than 1981 actually marketed.

(2) H-Oil pitch included in the blend.

(3) Calculated from the value of the blend.

(4) Pitch produced not sufficient for asphalt plant requirement.

(5) HFO production less than 1981 own consumption requirement.

(6) No saleable HFO available.

TABLE 6.2.1.6

REFINERY'S OWN FUEL CONSUMPTION, SALEABLE FUEL OIL AND VACUUM RESID

QUEBEC REGION

CASE		ANNUAL FLOWRATE	REFINERY'S OWN CONSUMPTION				SALEABLE PRODUCTS **				VAC. RESID OR PITCH PRODUCT
			HFO	LFO	DIESEL	KERO/STOVE	HFO	LFO	DIESEL	KERO/STOVE	
B	SIMULATED	*m^3/y	518 027	4 974	24 156	422	5 358 962	4 662 630	2 739 181	313 858	1 186 315
&	BASE CASE &	BPCD	8 927	86	416	7	92 348	80 348	47 203	5 409	20 443
BR	BASE REF CASE	s.g.	0.9987	0.8523	0.8539	0.8203	0.9987	0.8523	0.8539	0.8203	1.0397
1	LFO - 0.3	m^3/y									
		BPCD				SAME	AS BASE	AND			
		s.g.									
2	LFO - 0.1	m^3/y				BASE	REF. CASES				
		BPCD									
		s.g.									
3	LFO - 0.3	m^3/y	(2) 518 027	4 974	24 156	422	1)(2) 30 800	4 662 630	2 739 181	313 858	1 186 315
	H-OIL:	BPCD	(2) 8 927	86	416	7	1)(2) 2 254	80 348	47 203	5 409	20 443
	LOW CONV.	s.g.	(3) 1.0380	0.8741	0.8449	0.8204	(3) 1.0380	0.8741	0.8449	0.8204	1.0430
4	LFO - 0.1	m^3/y									
	H-OIL:	BPCD				SAME	AS CASE	NO. 3			
	LOW CONV.	s.g.									
5	LFO - 0.3	m^3/y	(5) 517 051	4 974	24 156	422	(6) 0	4 662 630	2 739 181	313 858	(4) 376 559
	H-OIL:	BPCD	(5) 8 910	86	416	7	(6) 0	80 348	47 203	5 409	6 489
	HIGH CONV.	s.g.	1.0536	0.8843	0.8490	0.8205	1.0536	0.8843	0.8490	0.8205	1.1230
6	LFO - 0.1	m^3/y									
	H-OIL:	BPCD				SAME	AS CASE	NO. 6			
	HIGH CONV.	s.g.									

NOTES:

* Based on Statistics Canada publication: Refined Petroleum Products, Dec. 1981.
Assuming consumption remains the same for all cases in Atlantic and Ontario Regions.

** Calculated from *. For Cases B, BR, 1 & 2 Saleable Product = Net Production + Stock - Losses - Own Consumption.

(1) HFO available for sales less than 1981 actually marketed.
(2) H-Oil pitch included in the blend.
(3) Calculated from the value of the blend.
(4) Pitch produced not sufficient for asphalt plant requirement.
(5) HFO production less than 1981 own consumption requirement.
(6) No saleable HFO available.

TABLE 6.2.1.7

REFINERY'S OWN FUEL CONSUMPTION, SALEABLE FUEL OIL AND VACUUM RESID

ONTARIO REGION

	CASE	ANNUAL FLOWRATE	REFINERY'S OWN CONSUMPTION				SALEABLE PRODUCTS **				VAC. RESID OR PITCH PRODUCT
			HFO	LFO	DIESEL	KERO/STOVE	HFO	LFO	DIESEL	KERO/STOVE	
B	SIMULATED	* m^3/y	813 175	5 097	22 195	602	4 240 636	4 064 857	3 361 022	257 893	768 612
&	BASE CASE &	BPCD	14 013	88	382	10	73 076	70 047	57 918	4 444	13 245
BR	BASE REF CASE	s.g.	0.9980	0.8644	0.8409	0.8213	0.9980	0.8644	0.8409	0.8213	1.0350
1	LFO - 0.3	m^3/y									
		BPCD				SAME	AS BASE	AND			
		s.g.									
2	LFO - 0.1	m^3/y				BASE	REF. CASES				
		BPCD									
		s.g.									
3	LFO - 0.3	m^3/y	(2) 813 175	5 097	22 195	602	(1)(2) 1 328 605	4 064 857	3 361 022	257 993	768 612
	H-OIL:	BPCD	(2) 14 013	88	382	10	(1)(2) 22 895	70 047	57 918	4 444	13 245
	LOW CONV.	s.g.	(3) 0.9877	0.8569	0.8486	0.8197	(3) 0.9087	0.8569	0.8486	0.8197	1.0700
4	LFO - 0.1	m^3/y									
	H-OIL:	BPCD				SAME	AS CASE	NO. 3			
	LOW CONV.	s.g.									
5	LFO - 0.3	m^3/y	813 175	5 097	22 195	602	(1) 573 746	4 064 857	3 361 022	257 893	(4) 345 223
	H-OIL:	BPCD	14 013	88	382	10	(1) 9 877	70 047	57 918	4 444	(4) 5 949
	HIGH CONV.	s.g.	0.9825	0.8689	0.8510	0.8248	0.9825	0.8689	0.8510	0.8248	1.0875
6	LFO - 0.1	m^3/y									
	H-OIL:	BPCD				SAME	AS CASE	NO. 6			
	HIGH CONV.	s.g.									

NOTES:

* Based on Statistics Canada publication: Refined Petroleum Products, Dec. 1981. Assuming consumption remains the same for all cases in Atlantic and Ontario Regions.

** Calculated from *. For Cases B, BR, 1 & 2 Saleable Product = Net Production + Stock - Losses - Own Consumption.

(1) HFO available for sales less than 1981 actually marketed.

(2) H-Oil pitch included in the blend.

(3) Calculated from the value of the blend.

(4) Pitch produced not sufficient for asphalt plant requirement.

(5) HFO production less than 1981 own consumption requirement.

(6) No saleable HFO available.

TABLE 6.2.1.8

REFINERY'S OWN FUEL CONSUMPTION, SALEABLE FUEL OIL AND VACUUM RESID

WESTERN REGION

CASE		ANNUAL FLOWRATE	REFINERY'S OWN CONSUMPTION				SALEABLE PRODUCTS **				VAC. RESID OR PITCH PRODUCT
			HFO	LFO	DIESEL	KERO/STOVE	HFO	LFO	DIESEL	KERO/STOVE	
B	SIMULATED	* m^3/y	80 795	397	14 055	700	1 858 872	1 119 054	7 289 771	490 566	1 615 333
&	BASE CASE &	BPCD	1 392	7	242	12	32 033	19 284	125 620	8 454	27 836
BR	BASE REF CASE	s.g.	1.0230	0.8962	0.8499	0.8240	1.0230	0.8962	0.8499	0.8240	1.0567
1	LFO - 0.3	m^3/y									
		BPCD				SAME	AS BASE	AND			
		s.g.									
2	LFO - 0.1	m^3/y				BASE	REF. CASES				
		BPCD									
		s.g.									
3	LFO - 0.3	m^3/y	(2) 80 795	397	14 055	700	(1)(2) 397 956	1 119 054	7 289 771	490 566	(4) 176 160
	H-OIL:	BPCD	(2) 1 392	7	242	12	(1)(2) 6 858	19 284	125.620	8 454	(4) 20 268
	LOW CONV.	s.g.	(3) 1.0434	0.8980	0.8446	0.8240	(3) 1.0434	0.8980	0.8446	0.8240	1.0700
4	LFO - 0.1	m^3/y									
	H-OIL:	BPCD				SAME	AS CASE	NO. 3			
	LOW CONV.	s.g.									
5	LFO - 0.3	m^3/y	80 795	397	14 055	700	(1) 899 918	1 119 054	7 289 771	490 566	(4) 322 997
	H-OIL:	BPCD	1 392	7	242	12	(1) 15 508	19 284	125 620	8 454	(4) 5 566
	HIGH CONV.	s.g.	0.9962	0.8974	0.8457	0.8239	0.9962	0.8974	0.8457	0.8239	1.0875
6	LFO - 0.1	m^3/y									
	H-OIL:	BPCD				SAME	AS CASE	NO. 6			
	HIGH CONV.	s.g.									

NOTES:

* Based on Statistics Canada publication: Refined Petroleum Products, Dec. 1981.
Assuming consumption remains the same for all cases in Atlantic and Ontario Regions.

** Calculated from *. For Cases B, BR, 1 & 2 Saleable Product = Net Production + Stock - Losses - Own Consumption.

(1) HFO available for sales less than 1981 actually marketed.
(2) H-Oil pitch included in the blend.
(3) Calculated from the value of the blend.
(4) Pitch produced not sufficient for asphalt plant requirement.
(5) HFO production less than 1981 own consumption requirement.
(6) No saleable HFO available.

ANNUAL REDUCTION OF SULFUR IN FUEL OIL AND VACUUM RESID

ATLANTIC REGION

CASE	ANNUAL S * REDUCTION TONNE	(A) REFINERY'S FUEL CONSUMPTION **				(B) SALEABLE PRODUCTS **				VAC. RESID OR H-OIL PITCH TO ASPHALT PLANT TONNE	TOTAL *** TONNE
			LIGHT FUEL OILS				LIGHT FUEL OILS				
		HFO	LFO	DIESEL	KEROSENE/ STOVE	HFO	LFO	DIESEL	KEROSENE/ STOVE		
1	LFO S = 0.3 WT.% MAX.	2	3	5	0	28	2 506	455	29	0	3 028
		SUBTOTAL = 10					SUBTOTAL = 2 990				
2	LFO S = 0.1 WT.% MAX.	4	9	22	0	55	8 074	1 997	83	0	10 244
		SUBTOTAL = 35					SUBTOTAL = 10 154				
3	LFO, S = 0.3 WT.% MAX. + H-OIL LOW CONV.	827	3	5	0	66 751 (1)	2 403	418	29	6 498	70 436
		SUBTOTAL = 835					SUBTOTAL = 2 850				
4	LFO, S = 0.1 WT.% MAX. + H-OIL LOW CONV.	829	9	21	0	66 755 (1)	8 040	1 985	83	6 498	77 722
		SUBTOTAL = 859					SUBTOTAL = 10 108				
5	LFO, S = 0.3 WT.% MAX. + H-OIL HIGH CONV.	- 121	3	4	0	73 864 (1)	2 383	406	29	8 929	76 568
		SUBTOTAL = - 114					SUBTOTAL = 2 818				
6	LFO, S = 0.1 WT.% MAX. + H-OIL HIGH CONV.	- 121	9	22	0	73 864 (1)	8 005	2 004	83	8 929	83 866
		SUBTOTAL = - 90					SUBTOTAL = 10 092				

NOTES:

* Calculation based on reduction from Base Reference Case.

** Calculation based on data from Statistics Canada Pub.: Refined Petroleum Products 1981.

*** Excluding Vac. Resid or H-Oil Pitch to Asphalt Plant.

"-" Denotes an increase.

(1) Increased Sulfur reduction due to less "Saleable HFO" available (compared with that actually marketed in 1981.

TABLE 6.2.1.10

ANNUAL REDUCTION OF SULFUR IN FUEL OIL AND VACUUM RESID

QUEBEC REGION

CASE	ANNUAL S * REDUCTION TONNE	(A) REFINERY'S FUEL CONSUMPTION **				(B) SALEABLE PRODUCTS **				VAC. RESID OR H-OIL PITCH TO ASPHALT PLANT TONNE	TOTAL *** TONNE
		HFO	LIGHT FUEL OILS			HFO	LIGHT FUEL OILS				
			LFO	DIESEL	KEROSENE/ STOVE		LFO	DIESEL	KEROSENE/ STOVE		
1	LFO S = 0.3 WT.% MAX.	10	2	5	0	107	1 510	538	144	0	2 316
		SUBTOTAL = 17					SUBTOTAL = 2 192				
2	LFO S = 0.1 WT.% MAX.	10	10	46	0	107	9 458	5 216	221	0	15 068
		SUBTOTAL = 66					SUBTOTAL = 14 895				
3	LFO, S = 0.3 WT.% MAX. + H-OIL LOW CONV.	342	1	5	0	119 238 (1)	1 205	612	144	18 489	121 547
		SUBTOTAL = 348					SUBTOTAL = 1 961				
4	LFO, S = 0.1 WT.% MAX. + H-OIL LOW CONV.	342	10	46	0	119 238 (1)	9 356	5 250	221	18 489	134 463
		SUBTOTAL = 398					SUBTOTAL = 14 827				
5	LFO, S = 0.3 WT.% MAX. + H-OIL HIGH CONV.	-626	1	5	0	122 133 (1)	1 104	578	144	29 919	123 339
		SUBTOTAL = -620					SUBTOTAL = 1 826				
6	LFO, S = 0.1 WT.% MAX. + H-OIL HIGH CONV.	-620	10	46	0	122 133 (1)	9 268	5 229	221	29 919	136 287
		SUBTOTAL = -564					SUBTOTAL = 14 718				

NOTES:

- * Calculation based on reduction from Base Reference Case.
- ** Calculation based on data from Statistics Canada Pub.: Refined Petroleum Products 1981.
- *** Excluding Vac. Resid or H-Oil Pitch to Asphalt Plant.
- "-" Denotes an increase.
- (1) Increased Sulfur reduction due to less "Saleable HFO" available (compared with that actually marketed in 1981.

TABLE 6.2.1.11

ANNUAL REDUCTION OF SULFUR IN FUEL OIL AND VACUUM RESID

ONTARIO REGION

CASE	ANNUAL S * REDUCTION TONNE	(A) REFINERY'S FUEL CONSUMPTION **				(B) SALEABLE PRODUCTS **				VAC. RESID OR H-OIL PITCH TO ASPHALT PLANT TONNE	TOTAL *** TONNE
			LIGHT FUEL OILS				LIGHT FUEL OILS				
		HFO	LFO	DIESEL	KEROSENE/ STOVE	HFO	LFO	DIESEL	KEROSENE/ STOVE		
1	LFO S = 0.3 WT.% MAX.	0	0	0	0	0	0	0	0	0	0
		SUBTOTAL = 0					SUBTOTAL = 0				
2	LFO S = 0.1 WT.% MAX.	0	8	32	0	0	6 571	4 861	0	0	11 472
		SUBTOTAL = 40					SUBTOTAL = 11 432				
3	LFO, S = 0.3 WT.% MAX. + H-OIL LOW CONV.	2 499	0	0	0	(1) 51 920	87	-70	0	6 407	54 436
		SUBTOTAL = 2 499					SUBTOTAL = 17				
4	LFO, S = 0.1 WT.% MAX. + H-OIL LOW CONV.	2 507	8	32	0	(1) 51 933	6 601	4 835	0	6 407	65 916
		SUBTOTAL = 2 547					SUBTOTAL = 11 436				
5	LFO, S = 0.3 WT.% MAX. + H-OIL HIGH CONV.	2 085	0	0	0	(1) 61 707	-53	-92	-1	12 575	63 646
		SUBTOTAL = 2 085					SUBTOTAL = -146				
6	LFO, S = 0.1 WT.% MAX. + H-OIL HIGH CONV.	2 093	8	32	0	(1) 61 713	6 552	4 827	-1	12 575	75 224
		SUBTOTAL = 2 133					SUBTOTAL = 11 378				

NOTES:

- * Calculation based on reduction from Base Reference Case.
- ** Calculation based on data from Statistics Canada Pub.: Refined Petroleum Products 1981.
- *** Excluding Vac. Resid or H-Oil Pitch to Asphalt Plant.
- "-" Denotes an increase.
- (1) Increased Sulfur reduction due to less "Saleable HFO" available (compared with that actually marketed in 1981.

TABLE 6.2.1.12

ANNUAL REDUCTION OF SULFUR IN FUEL OIL AND VACUUM RESID

WESTERN REGION

CASE	ANNUAL S * REDUCTION TONNE	(A) REFINERY'S FUEL CONSUMPTION **				(B) SALEABLE PRODUCTS **				VAC. RESID OR H-OIL PITCH TO ASPHALT PLANT TONNE	TOTAL*** TONNE
		HFO	LIGHT FUEL OILS			HFO	LIGHT FUEL OILS				
			LFO	DIESEL	KEROSENE/ STOVE		LFO	DIESEL	KEROSENE/ STOVE		
1	LFO S = 0.3 WT.% MAX.	2	0	0	0	57	762	0	0	0	821
		SUBTOTAL = 2					SUBTOTAL = 762				
2	LFO S = 0.1 WT.% MAX.	7	1	8	0	171	2 768	4 027	0	0	6 982
		SUBTOTAL = 16					SUBTOTAL = 6 795				
3	LFO, S = 0.3 WT.% MAX. + H-OIL LOW CONV.	91	0	0	0	(1) 21 296	756	64	0	22 483	22 207
		SUBTOTAL = 91					SUBTOTAL = 820				
4	LFO, S = 0.1 WT.% MAX. + H-OIL LOW CONV.	91	1	8	0	(1) 21 296	2 766	4 004	0	22 483	28 166
		SUBTOTAL = 100					SUBTOTAL = 6 770				
5	LFO, S = 0.3 WT.% MAX. + H-OIL HIGH CONV.	132	0	0	0	(1) 15 160	758	51	0	33 642	16 101
		SUBTOTAL = 132					SUBTOTAL = 809				
6	LFO, S = 0.1 WT.% MAX. + H-OIL HIGH CONV.	132	1	8	0	(1) 15 160	2 767	3 996	0	33 642	22 064
		SUBTOTAL = 141					SUBTOTAL = 6 763				

NOTES:

* Calculation based on reduction from Base Reference Case.

** Calculation based on data from Statistics Canada Pub.: Refined Petroleum Products 1981.

*** Excluding Vac. Resid or H-Oil Pitch to Asphalt Plant.

"-" Denotes an increase.

(1) Increased Sulfur reduction due to less "Saleable HFO" available (compared with that actually marketed in 1981.

6.2.2 Revised Crude Oil Requirements, Product Rates, and Hydrogen Balance

Since the sulfur reductions in Cases 1 and 2 were achieved by hydrotreating the blending stocks of the fuel oil products lighter than HFO, the liquid product slates as well as the crude oil requirements were essentially unchanged. The impact of the variation of hydrotreater operation and fuel gas and naphtha production rates on the crude oil requirements are relatively small. The crude oil requirements of Cases 3 to 6 where H-Oil processes have been added to process all the vacuum resid, are substantially reduced. The crude oil requirements in each of the four regions as a result of imposing different limits of sulfur contents on the fuel oil products and addition of H-Oil units are presented in Tables 6.2.2.1 to 4. The products which rates are affected and the hydrogen balance are also included in the tables. The changes in crude oil requirements and the product rates with respects to the reference base cases are summarized in Tables 6.2.2.5 to 8.

6.2.2.1 Crude Oil Requirements

The reduction in crude oil requirements in the four regions for cases with H-Oil units, are:-

Cases 3 and 4	Atlantic - 20%; Quebec - 20%; Ontario - 9%; Western - 6.5%.
Cases 5 and 6	Atlantic - 24%; Quebec - 22%; Ontario - 15%; Western - 7.5%.

Since the sulfur contents of LFO and the lighter liquid products were reduced by merely increasing hydrotreating of the blending stocks, the requirements of crude oils for Cases 3 and 4 are the same. In Cases 5 and 6 where the H-Oil units are at higher conversion levels, there are additional reductions in the crude oil requirements.

The reductions in crude oil requirements by means of adding H-Oil units depend on the amount of lighter liquid product produced by H-Oil process and how effectively these materials can be utilized in blending of LFO and lighter products or converted to the desired products. Therefore it is obvious that the higher conversion H-Oil units would have some advantages over the low conversion ones in terms of crude oil reduction.

The crude diets of Atlantic and Quebec regions have higher proportions of the $975^{0}F^{+}$ material which can be converted to the lighter products for reforming, cracking and product blending. The 1981 product slates of these two regions are probably more compatible with the product slates of H-Oil units. Ontario and the Western regions have lower proportions of the $975^{0}F^{+}$ material in their crude diets. Their 1981 product slates have higher proportions of naphtha products than the other two regions. The flexibilities in process unit throughputs were also less due to their higher utilization of the refineries capacities. The vacuum units and the catalytic cracking units in these two regions were near full utilization in most cases where H-Oil units were added. Consequently, less crude reductions were realized in these two regions.

6.2.2.2 Heavy Fuel Oil and Vacuum Resid Products

Production of the heavy fuel oils and vacuum resids in Cases 1 and 2 are the same as the reference base cases. Different degrees of hydrotreating are reflected in the mass balances of fuel gas, hydrogen and naphtha which will be discussed later. In Cases 3 and 4, there are reductions in the HFO and heavier products. The HFO's were blended from mostly HCO and reduced crude. The resid/pitch from the H-Oil vacuum bottoms can also be blended into HFO to the extent permitted by the viscosity spec. Allocation of the resid/pitch from the H-Oil units at low conversion operation was based on satisfying the asphalt making and coking market first and blending the remaining resid into HFO if the viscosity spec. can be met. On this basis, product rates to asphalt making and coking market for Cases 3 and 4 were maintained at the same rates as the reference base cases, for all regions except the Western region where the available resid/pitch was slightly less than the 1981 market demand. The HFO productions of Cases 3 and 4 were all substantially less than those of the refernce base cases. The reductions of HFO were most pronounced in Atlantic and Quebec regions for the reasons discussed earlier for the crude oil reductions.

In Cases 5 and 6, due to high conversion operation, the production of resid/pitch from the H-Oil units cannot even satisfy the 1981 market for asphalt making and coking. The HFO's were blended mostly from HCO and reduced crude, and the productions are also substantially lower than the reference base cases.

In all cases, the reductions of HFO and resid production correspond to the reductions in crude requirements; they are more pronounced in the Atlantic and Quebec regions.

6.2.2.3 Sulfur Products

Higher desulfurization in the fuel oil products are reflected in higher sulfur production as shown by Cases 1 and 2. Since H-Oil process also desulfurizes the liquid products, sulfur production for cases with H-Oil units (Cases 3 to 6) are significantly higher than Cases 1 and 2. The increases in sulfur products are not the same as the sulfur reductions in fuel oil products presented in the earlier section because part of the sulfur reductions are due to reductions in the production rates of HFO and heavier products.

Regionally, sulfur productions are higher in the Atlantic and Quebec regions which use crudes having higher sulfur contents.

6.2.2.4 Fuel Gas and Naphtha Products and Hydrogen Balance

In the computer print-outs, the fuel gases include significant proportions of C_3's and C_4's. For comparison between cases, the fuel gases after deducting the hydrogen for hydrotreating and hydrocracking were credited as products without considering the actual fuel balance and the fuel gas utilization of the refineries. In practice, the C_3's and C_4's probably would be recovered as LPG products, the hydrogen rich reformer gas would be used for hydrotreating and hydrocracking, and the surplus in the fuel gas would then be consumed as fuel. In the study cases, the incremental fuel gas may be used to displace the HFO consumed within the refineries. The details of fuel balance have not been covered in this study.

Due to the limitation of the computer model, the relatively small amount of naphthas produced by the hydrotreaters termed as "Delta Naphtha" in the print-outs (Part II), were not added to the main naphtha streams (Stream 3 in the block flow diagram). Instead they were treated as additional products and credited accordingly to the operating costs. If naphtha is required as feed to the hydrogen plant, these "Delta Naphtha" would be used first. Additional requirement would then be imported as shown in Table 6.2.2.5.

The hydrogen demand for the hydrotreaters and the H-Oil units are provided by the hydrogen produced by the reformers. If the supply is not adequate, make-up hydrogen would then be generated by the additional hydrogen plants fed by natural gas, as in Cases 3 to 6 of Quebec region where natural gas is available or fed by naphtha, as in Cases 3 to 6 of Atlantic region where natural gas is not available. The amount of naphtha required using steam reforming process was based on 12.32 lb/MSCF H_2 (13). The mole ratio of hydrogen to natural gas was assumed to be 3.65 for the methane steam reforming process. The compression facility was included to bring the pressure to the level required for hydrotreating or H-Oil process.

TABLE 6.2.2.1

COMPARISON OF CRUDE FEED REQUIREMENT, PRODUCT RATES AND HYDROGEN PRODUCTION

ATLANTIC REGION

CASE	FEED			PETROLEUM PRODUCTS						
	CRUDE	IMPORTED HYDROGEN	TOTAL VACUUM RESID/ H-OIL FEED	HFO*	VACUUM RESID/PITCH		HYDROGEN (TO HTU AND H-OIL)	REFINERY FUEL GAS ▲	NAPHTHA FROM HTU △	SULFUR
					TO ASPHALT PLANT	TO COKING				
	BPCD	MMSCFD	BPCD	BPCD	BPCD	BPCD	MMSCFCD	MMBTU/CD	BPCD	STPCD
B	220,692	0	40,870	52,516	4,939	1,250	30.3	67,822	283	191
BR	220,692	0	40,870	52,516	4,939	1,250	28.6	67,749	279	191
1	220,692	0	40,870	52,516	4,939	1,250	33.1	67,393	275	200
2	220,692	0	40,870	52,516	4,939	1,250	45.5	66,143	428	228
3	176,044	14.5	35,577	4,680 5,303 ▽ 9,983	4,939	1,250	(1) 58.8	74,191	118	305
4	176,044	31.1	35,577	4,680 5,303 ▽ 9,983	4,939	1,250	(1) 58.7	77,164	398	328
5	168,721	23.8	34,112	4,440	(2) 3,241	(3) 0	(1) 60.4	83,375	115	313
6	168,721	41.2	34,112	4,440	(2) 3,241	(3) 0	(1) 60.4	86,505	412	335

NOTES: Gasoline, aviation turbo fuels, distillate production, naphtha specialties, petrochemical feedstocks and feed to Lube Oil are maintained same as 1981 figures according to Statistics Canada.

* Including own consumption.

▲ Net fuel gas (including C_4's and those from HTU's) with an LHV as shown in the computer print-outs.

△ Naphtha is from HTU's except those produced by H-Oil.

▽ H-Oil pitch.

(1) Max. hydrogen available (add imported hydrogen for total requirements).

(2) Pitch produced not sufficient for 1981 asphalt plant requirement.

(3) No pitch available for coking.

TABLE 6.2.2.2

COMPARISON OF CRUDE FEED REQUIREMENT, PRODUCT RATES AND HYDROGEN PRODUCTION

QUEBEC REGION

CASE	FEED			PETROLEUM PRODUCTS						
	CRUDE	IMPORTED HYDROGEN	TOTAL VACUUM RESID/ H-OIL FEED	HFO*	VACUUM RESID/PITCH		HYDROGEN (TO HTU AND H-OIL)	REFINERY FUEL GAS ▲	NAPHTHA FROM HTU △	SULFUR
					TO ASPHALT PLANT	TO COKING				
	BPCD	MMSCFD	BPCD	BPCD	BPCD	BPCD	MMSCFCD	MMBTU/CD	BPCD	STPCD
B	484,623	0	80,299	102,591	18,175	2,268	44.4	169,201	288	203
BR	484,623	0	80,299	102,591	18,175	2,268	43.4	169,153	323	203
1	484,623	0	80,299	102,591	18,175	2,268	51.4	168,675	396	211
2	484,623	0	80,299	102,591	18,175	2,268	69.9	166,402	592	251
3	388,986	4.9	70,633	8,810 2,371 ▽ 11,181	18,175	2,268	(1) 122.6	181,836	72	470
4	388,986	33.8	70,633	8,810 2,371 ▽ 11,181	18,175	2,268	(1) 122.6	186,859	537	510
5	376,039	34.6	68,304	8,910	(2) 6,489	(3) 0	(1) 118.6	204,903	101	485
6	376,039	64.2	68,304	8.910	(2) 6,489	(3) 0	(1) 118.6	210.156	602	525

NOTES: Gasoline, aviation turbo fuels, distillate production, naphtha specialties, petrochemical feedstocks and feed to Lube Oil are maintained same as 1981 figures according to Statistics Canada.

* Including own consumption.

▲ Net fuel gas (including C_4's and those from HTU's) with an LHV as shown in the computer print-outs.

△ Naphtha is from HTU's except those produced by H-Oil.

▽ H-Oil pitch.

(1) Max. hydrogen available (add imported hydrogen for total requirements).

(2) Pitch produced not sufficient for 1981 asphalt plant requirement.

(3) No pitch available for coking.

COMPARISON OF CRUDE FEED REQUIREMENT, PRODUCT RATES AND HYDROGEN PRODUCTION

ONTARIO REGION

CASE	FEED		TOTAL VACUUM RESID/ H-OIL FEED	PETROLEUM PRODUCTS						
	CRUDE	IMPORTED HYDROGEN		HFO*	VACUUM RESID/PITCH		HYDROGEN (TO HTU AND H-OIL)	REFINERY FUEL GAS ▲	NAPHTHA FROM HTU △	SULFUR
					TO ASPHALT PLANT	TO COKING				
	BPCD	MMSCFD	BPCD	BPCD	BPCD	BPCD	MMSCFCD	MMBTU/CD	BPCD	STPCD
B	565,954	0	54,162	87,612	8,883	4,362	31.0	191,552	178	106.3
BR	565,954	0	54,162	87,612	8,883	4,362	27.1	191,754	39	106.4
1	565,954	0	54,162	87,612	8,883	4,362	27.1	191,754	39	106.4
2	565,953	0	54,162	87,612	8,883	4,362	50.7	188,707	290	139.4
3	515,422	0	58,290	31,500 5,408 ▽ 36,908	8,883	4,362	62.4	209,102	13	248.7
4	515,422	0	58,290	31,500 5,408 ▽ 36,908	8,883	4,362	101.3	201,658	211	281.7
5	494,102	0	58,323	23,900	(2) 5,949	(3) 0	79:6	207,201	25	273.7
6	494,102	0	58,323	23,900	(2) 5,949	(3) 0	104.7	204,216	337	307.0

NOTES: Gasoline, aviation turbo fuels, distillate production, naphtha specialties, petrochemical feedstocks and feed to Lube Oil are maintained same as 1981 figures according to Statistics Canada.

* Including own consumption.

▲ Net fuel gas (including C_4's and those from HTU's) with an LHV as shown in the computer print-outs.

△ Naphtha is from HTU's except those produced by H-Oil.

▽ H-Oil pitch.

(1) Max. hydrogen available (add imported hydrogen for total requirements).

(2) Pitch produced not sufficient for 1981 asphalt plant requirement.

(3) No pitch available for coking.

TABLE 6.2.2.4

COMPARISON OF CRUDE FEED REQUIREMENT, PRODUCT RATES AND HYDROGEN PRODUCTION

WESTERN REGION

CASE	FEED		TOTAL VACUUM RESID/ H-OIL FEED	PETROLEUM	PRODUCTS					
	CRUDE	IMPORTED HYDROGEN		HFO*	VACUUM RESID/PITCH		HYDROGEN (TO HTU AND H-OIL)	REFINERY FUEL GAS ▲	NAPHTHA FROM HTU △	SULFUR
					TO ASPHALT PLANT	TO COKING				
	BPCD	MMSCFD	BPCD	BPCD	BPCD	BPCD	MMSCFCD	MMBTU/CD	BPCD	STPCD
B	534,463	0	43,297	33,057	21,693	6,143	45.8	256,084	321	123.2
BR	534,463	0	43,297	33,057	21,693	6,143	38.1	256,246	63	123.5
1	534,463	0	43,297	33,057	21,693	6,143	39.5	256,022	64	126.0
2	534,463	0	43,297	33,057	21,693	6,143	54.4	254,254	254	145.0
3	499,725	0	59,612	8,250	(2) 20,268	(3) 0	76.1	267,575	105	234.3
4	499,725	0	59,612	8,250	(2) 20,268	(3) 0	88.3	265,844	164	252.8
5	494,221	0	55,662	16,900	(2) 5,566	(3) 0	86.3	273,543	104	244.6
6	494,221	0	55,662	16,900	(2) 5,566	(3) 0	99.9	275,624	230	262.7

NOTES: Gasoline, aviation turbo fuels, distillate production, naphtha specialties, petrochemical feedstocks and feed to Lube Oil are maintained same as 1981 figures according to Statistics Canada.

* Including own consumption.

▲ Net fuel gas (including C_4's and those from HTU's) with an LHV as shown in the computer print-outs.

△ Naphtha is from HTU's except those produced by H-Oil.

▽ H-Oil pitch.

(1) Max. hydrogen available (add imported hydrogen for total requirements).

(2) Pitch produced not sufficient for 1981 asphalt plant requirement.

(3) No pitch available for coking.

TABLE 6.2.2.5

INCREMENTAL FEED AND PRODUCT RATES

ATLANTIC REGION

CASE	CRUDE FEED BPCD	HYDROGEN PLANT		PETROLEUM PRODUCTS					
		Fr NAPHTHA BPCD (LB/HR)	Fr NAT. GAS MMSCF/CD	HFO (4) BPCD	RESID TO (3) ASPHALT BPCD	H_2 (2) OWN USE MMSCF/CD	REFINERY(1) FUEL GAS MMBTU/CD	NAPHTHA BPCD	SULFUR ST/CD
1	0	0	0	0	0	4.5	- 356	- 4	9.3
2	0	0	0	0	0	16.9	- 1,606	149	37.5
3	- 44,648	584 (6,216)	0	- 42,533	0	30.2 (5)	6,442	- 161	114.4
4	- 44,648	1,101 (11,721)	0	- 42,533	0	30.1 (5)	9,415	119	137.4
5	- 51,971	1,033 (10,998)	0	- 48,076	- 2,948	31.8 (5)	15,626	- 164	121.7
6	- 51,971	1,576 (16,782)	0	- 48,076	- 2,948	31.8 (5)	18,756	133	144.6

NOTES: Gasoline, aviation turbo fuels, distillate production, naphtha specialties, petrochemical feedstocks and feed to Lube Oil are maintained same as 1981 figures according to Statistics Canada.

Case BR was used as a reference for comparison.

(1) Net fuel gas (including C_4's and those from HTU's) with an LHV as shown in the computer print-outs.

(2) Calculated by adjusting lb/hr. in the computer print-outs.

(3) Product residue/pitch to asphalt plant.

(4) HFO including own consumption.

(5) Maximum available.

"-" denotes a decrease in flowrate.

TABLE 6.2.2.6

INCREMENTAL FEED AND PRODUCT RATES

QUEBEC REGION

CASE	CRUDE FEED BPCD	HYDROGEN PLANT		PETROLEUM PRODUCTS					
		Fr NAPHTHA BPCD (LB/HR)	Fr NAT. GAS MMSCF/CD	HFO (4) BPCD	RESID TO (3) ASPHALT BPCD	H_2 (2) OWN USE MMSCF/CD	REFINERY(1) FUEL GAS MMBTU/CD	NAPHTHA BPCD	SULFUR ST/CD
1	0	0	0	0	0	8.0	- 478	73	8.3
2	0	0	0	0	0	26.5	- 2,751	269	47.7
3	- 95,637	0	1.4	- 91,410	0	79.2 (5)	12,683	- 251	267.0
4	- 95,637	0	9.5	- 91,410	0	79.2 (5)	17,706	214	306.7
5	- 108,584	0	9.8	- 93,681	- 13,954	75.2 (5)	37,750	- 222	281.4
6	- 108,584	0	18.1	- 93,681	- 13,954	75.2 (5)	41,003	279	321.9

NOTES: Gasoline, aviation turbo fuels, distillate production, naphtha specialties, petrochemical feedstocks and feed to Lube Oil are maintained same as 1981 figures according to Statistics Canada.

Case BR was used as a reference for comparison.

(1) Net fuel gas (including C_4's and those from HTU's) with an LHV as shown in the computer print-outs.

(2) Calculated by adjusting lb/hr. in the computer print-outs.

(3) Product residue/pitch to asphalt plant.

(4) HFO including own consumption.

(5) Maximum available.

"-" denotes a decrease in flowrate.

TABLE 6.2.2.7

INCREMENTAL FEED AND PRODUCT RATES

ONTARIO REGION

CASE	CRUDE FEED BPCD	HYDROGEN PLANT		PETROLEUM PRODUCTS					
		Fr NAPHTHA BPCD (LB/HR)	Fr NAT. GAS MMSCF/CD	HFO (4) BPCD	RESID TO (3) ASPHALT BPCD	H_2 (2) OWN USE MMSCF/CD	REFINERY(1) FUEL GAS MMBTU/CD	NAPHTHA BPCD	SULFUR ST/CD
1	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	23.6	- 3,047	251	33.0
3	- 50,532	0	0	- 50,704	0	35.3	17,348	- 26	142.3
4	- 50,532	0	0	- 50,704	0	74.2	9,904	172	175.3
5	- 71,852	0	0	- 63,712	- 7,296	52.5	15,447	- 14	167.3
6	- 71,852	0	0	- 63,712	- 7,296	77.6	12,462	298	200.6

NOTES: Gasoline, aviation turbo fuels, distillate production, naphtha specialties, petrochemical feedstocks and feed to Lube Oil are maintained same as 1981 figures according to Statistics Canada.

Case BR was used as a reference for comparison.

(1) Net fuel gas (including C_4's and those from HTU's) with an LHV as shown in the computer print-outs.

(2) Calculated by adjusting lb/hr. in the computer print-outs.

(3) Product residue/pitch to asphalt plant.

(4) HFO including own consumption.

(5) Maximum available.

"-" denotes a decrease in flowrate.

TABLE 6.2.2.8

INCREMENTAL FEED AND PRODUCT RATES

WESTERN REGION

CASE	CRUDE FEED BPCD	HYDROGEN PLANT		PETROLEUM PRODUCTS					
		Fr NAPHTHA BPCD (LB/HR)	Fr NAT. GAS MMSCF/CD	HFO (4) BPCD	RESID TO (3) ASPHALT BPCD	H_2 (2) OWN USE MMSCF/CD	REFINERY(1) FUEL GAS MMBTU/CD	NAPHTHA BPCD	SULFUR ST/CD
1	0	0	0	0	0	1.4	- 224	1	2.5
2	0	0	0	0	0	16.3	- 1,992	191	21.5
3	- 34,738	0	0	- 24,807	- 7,568	38.0	11,329	42	110.8
4	- 34,738	0	0	- 24,807	- 7,568	50.2	9,598	101	129.3
5	- 40,242	0	0	- 16,157	- 22,270	48.2	17,297	41	121.1
6	- 40,242	0	0	- 16,157	- 22,270	61.8	19,378	167	139.2

NOTES: Gasoline, aviation turbo fuels, distillate production, naphtha specialties, petrochemical feedstocks and feed to Lube Oil are maintained same as 1981 figures according to Statistics Canada.

Case BR was used as a reference for comparison.

(1) Net fuel gas (including C_4's and those from HTU's) with an LHV as shown in the computer print-outs.

(2) Calculated by adjusting lb/hr. in the computer print-outs.

(3) Product residue/pitch to asphalt plant.

(4) HFO including own consumption.

(5) Maximum available.

"-" denotes a decrease in flowrate.

6.2.3 Changes in Process Unit Throughput

The installed capacity of refinery process units, such as crude unit, vacuum unit, reformer, catalytic cracker, naphtha hydrotreater, distillate and gas oil hydrotreaters and H-Oil unit and the utilized capacities of these units which are subject to change due to different degrees of desulfurization are tabulated in Tables 6.2.3.1 to 8.

In all cases, the installed capacities of crude, vacuum, reforming and cracking units have not been exceeded. However, almost full utilization of vacuum unit and catalytic cracker were experienced in Ontario and Western regions, and their impact on crude oil reduction has been discussed in Section 6.2.2.

The installed distillate and gas oil hydrotreaters throughput were estimated as discussed in Section 3.5.3. Hydrotreating capacity required by H-Oil distillate/light gas oil product was assigned to LGO hydrotreater and only in one case (Ontario Case 6) that it had to be assigned to HCO hydrotreater. It is obvious that utilization of hydrotreaters would be more in the lower sulfur limit cases, e.g. Case 2 more than Case 1, Case 4 more than Case 3 and Case 6 more than Case 5. The difference is less pronounced in Western region.

In all cases, there is no requirement for additional hydrotreater capacity for naphtha, LGO, LCO and HCO. There is however a requirement of additional kerosene hydrotreating capacities for Cases 2, 4 and 6 of Atlantic region based on the distribution of hydrotreating capacities established earlier in Section 3.5.3.2. The required throughput of kerosene hydrotreaters and the H-Oil installation to treat all vacuum resid produced are shown in Tables 6.2.3.5 to 8.

The additional capacities required for process units and the related ancillary units for all cases and the four regions are summarized in Tables 6.2.3.9 to 12.

The basis of the installed capacities of the sulfur plants and sour water strippers have been discussed in Section 3.5. Details on the installed capacities of the amine plants in 1981 were not available. In this study, sour fuel gas production rates of all cases are less than those of the reference base cases in volumetric flow, though the sulfur removal from these gases were higher with respect to the reference base cases. It is likely that the existing amine system can accommodate the sour fuel gas with higher sulfur. Since the costs of amine plants are relatively low, for capital investment estimate, it was assumed no additional amine plant is required for all cases.

Sulfur was recovered in a centralized facility for the refineries in Montreal, Quebec. Investment estimate for the additional sulfur plants was done on the same basis.

TABLE 6.2.3.1

INSTALLED & UTILIZED CAPACITIES OF CRUDE, VACUUM, CAT REFORMING AND CAT CRACKING UNITS

ATLANTIC REGION

CASE	UNIT FLOWRATE	CRUDE		VACUUM		CAT REFORMER		CAT CRACKER	
		BPCD	% UTILIZED	BPCD	% UTILIZED	BPCD	% UTILIZED	BPCD	% UTILIZED
0	INSTALLED CAPACITY	354,473	N/A	107,993	N/A	49,062	N/A	78,311 (1)	N/A
B	SIMULATED BASE CASE	220,692	62.3	94,695	87.7	30,655	62.5	62,226	79.5
BR	BASE REFERENCE	220,692	62.3	94,695	87.7	30,646	62.5	62,226	79.5
1	LFO - 0.3	220,692	62.5	94,695	87.7	30,705	62.6	62,226	79.5
2	LFO - 0.1	220,692	62.3	94,695	87.7	30,711	62.6	62,226	79.5
3	LFO - 0.3 H-OIL: LOW CONV.	176,044	49.7	75,492	69.9	28,204	57.5	62,500	79.8
4	LFO - 0.1 H-OIL: LOW CONV.	176,044	49.7	75,492	69.9	28,173	57.4	62,500	79.6
5	LFO - 0.3 H-OIL: HIGH CONV.	168,721	47.6	72,382	67.0	28,195	57.5	63,200	80.7
6	LFO - 0.1 H-OIL: HIGH CONV.	168,721	47.6	72,382	67.0	28,167	57.4	63,200	80.7

NOTE: (1) Includes 30,391 BPCD hydrocracker.

TABLE 6.2.3.2

INSTALLED & UTILIZED CAPACITIES OF CRUDE, VACUUM, CAT REFORMING AND CAT CRACKING UNITS

QUEBEC REGION

CASE \ UNIT FLOWRATE		CRUDE		VACUUM		CAT REFORMER		CAT CRACKER	
		BPCD	% UTILIZED	BPCD	% UTILIZED	BPCD	% UTILIZED	BPCD	% UTILIZED
0	INSTALLED CAPACITY	589,876	N/A	234,164	N/A	111,647	N/A	161,463[1]	N/A
B	SIMULATED BASE CASE	484,623	82.2	193,219	82.5	74,277	66.5	133,425	82.6
BR	BASE REFERENCE	484,623	82.2	193,219	82.5	74,260	66.5	133,425	82.6
1	LFO - 0.3	484,623	82.2	193,219	82.5	74,246	66.5	133,425	82.6
2	LFO - 0.1	484,623	82.2	193,219	82.5	74,319	66.6	133,425	82.6
3	LFO - 0.3 H-OIL: LOW CONV.	388,986	65.9	155,461	66.4	65,328	58.5	141,000	87.3
4	LFO - 0.1 H-OIL: LOW CONV.	388,986	65.9	155,461	66.4	65,320	58.5	141,000	87.3
5	LFO - 0.3 H-OIL: HIGH CONV.	376,039	63.7	150,355	64.2	64,049	57.4	148,000	91.7
6	LFO - 0.1 H-OIL: HIGH CONV.	376,039	63.7	150,355	64.2	64,012	57.3	148,000	91.7

NOTE: (1) Includes 29,186 BPCD hydrocracker.

TABLE 6.2.3.3

INSTALLED & UTILIZED CAPACITIES OF CRUDE, VACUUM, CAT REFORMING AND CAT CRACKING UNITS

ONTARIO REGION

CASE / UNIT FLOWRATE		CRUDE		VACUUM		CAT REFORMER		CAT CRACKER	
		BPCD	% UTILIZED	BPCD	% UTILIZED	BPCD	% UTILIZED	BPCD	% UTILIZED
0	INSTALLED CAPACITY	755,366	N/A	157,313	N/A	144,607	N/A	164,200[(1)]	N/A
B	SIMULATED BASE CASE	565,954	74.9	157,099	99.9	80,677	55.8	145,000	88.3
BR	BASE REFERENCE	565,954	74.9	157,099	99.9	80,743	55.8	145,000	88.3
1	LFO - 0.3	565,954	74.9	157,099	99.9	80,743	55.8	145,000	88.3
2	LFO - 0.1	565,954	74.9	157,099	99.9	80,891	55.9	145,000	88.3
3	LFO - 0.3 H-OIL: LOW CONV.	515,422	68.2	157,055	99.8	71,123	49.2	156,715	95.4
4	LFO - 0.1 H-OIL: LOW CONV.	515,422	68.2	157,055	99.8	71,298	49.3	156.715	95.4
5	LFO - 0.3 H-OIL: HIGH CONV.	494,102	65.4	157,143	99.9	68,172	47.1	156,715	95.4
6	LFO - 0.1 H-OIL: HIGH CONV.	494,102	65.4	157,143	99.9	68,289	47.2	156,715	95.4

NOTE: (1) Includes 7,485 BPCD hydrocracker.

TABLE 6.2.3.4

INSTALLED & UTILIZED CAPACITIES OF CRUDE, VACUUM, CAT REFORMING AND CAT CRACKING UNITS

WESTERN REGION

CASE	UNIT FLOWRATE	CRUDE		VACUUM		CAT REFORMER		CAT CRACKER	
		BPCD	% UTILIZED	BPCD	% UTILIZED	BPCD	% UTILIZED	BPCD	% UTILIZED
0	INSTALLED CAPACITY	537,795	N/A	169,767	N/A	97,306	N/A	154,231 (1)	N/A
B	SIMULATED BASE CASE	534,463	99.4	169,737	100.0	70,244	72.2	147,799	95.8
BR	BASE REFERENCE	534,463	99.4	169,737	100.0	70,377	72.3	147,799	95.8
1	LFO - 0.3	534,463	99.4	169,737	100.0	70,398	72.3	147,799	95.8
2	LFO - 0.1	534,463	99.4	169,737	100.0	70,464	72.4	147,799	95.8
3	LFO - 0.3 H-OIL: LOW CONV.	499,725	92.9	166,027	97.8	68,176	70.1	150,900	97.8
4	LFO - 0.1 H-OIL: LOW CONV.	499,725	92.9	166,027	97.8	68,311	70.2	150,900	97.8
5	LFO - 0.3 H-OIL: HIGH CONV.	494,221	91.9	155,024	91.3	65,191	67.0	152,847	99.1
6	LFO - 0.1 H-OIL: HIGH CONV.	494,221	91.9	155,024	91.3	65,294	67.1	152,847	99.1

NOTE: (1) Includes 1,384 BPCD hydrocracker.

TABLE 6.2.3.5

UTILIZATION OF INSTALLED AND ADDITIONAL CAPACITIES OF HYDROTREATERS AND H-OIL UNITS

ATLANTIC REGION

CASE	HTU	NAPHTHA BPCD	DISTILLATE AND GAS OIL						H-OIL UNIT (VAC. RESID) BPCD	ADDITIONAL CAPACITY BPCD
			KEROSENE BPCD	LGO & HO-LO BPCD	LCO BPCD	HCO BPCD	TOTAL BPCD	% UTILIZED		
	INSTALLED CAPACITY	64,571	22,350	33,700	22,750	6,100*	84,900	N/A	0	N/A
B	SIMULATED BASE	30,500	7,180	26,045	9,019	5,685	47,929	56.5	0	0
BR	BASE REF.	30,500	1,564	28,678	7,991	5,147	43,380	51.1	0	0
1	LFO S = 0.3 WT.% MAX.	30,500	8,233	25,794	16,312	3,241	53,580	63.1	0	0
2	LFO S = 0.1 WT.% MAX.	30,500	22,350 (1)	31,229	22,719	1,080	77,378	91.1	0	KERO: 10,472
3	LFO, S = 0.3 WT.% MAX. + H-OIL LOW CONV.	28,234	6,246	10,653	18,763	424	36,086	42.5	35,577	H-OIL: 35,577 (LO-CONV.)
4	LFO, S = 0.1 WT.% MAX. + H-OIL LOW CONV.	28,234	22,350 (1)	19,700 + 12,096** 31,790	18,763	422	73,325	86.4	35,577	KERO: 3,467 H-OIL: 35,577 (LO-CONV.)
5	LFO, S = 0.3 WT.% MAX. + H-OIL HIGH CONV.	28,187	5,856	10,048 + 15,725** 25,773	17,947	706	50,282	59.2	34,112	H-OIL: 34,112 (HI-CONV.)
6	LFO, S = 0.1 WT.% MAX. + H-OIL HIGH CONV.	28,187	22,350 (1)	17,954 + 15,725** 33,679	17,947	706	74,682	88.0	34,112	KERO: 1,908 H-OIL: 34,112 (HI-CONV.)

NOTES:

* Environment Canada DSS File No. 37SS.KE 204-0-0516, A Study on Heavy Oil Desulphurization in the Petroleum Industry (1981).

** H-Oil, light oil HTU capacity.

● Same as Case B and Case BR.

(1) 100% utilization of installed KERO-HTU capacity, see additional capacity required.

(2) Assigned 9,072 BPCD HO-LO to HCO HT.

TABLE 6.2.3.6

UTILIZATION OF INSTALLED AND ADDITIONAL CAPACITIES OF HYDROTREATERS AND H-OIL UNITS

QUEBEC REGION

CASE	HTU	NAPHTHA BPCD	DISTILLATE AND GAS OIL						H-OIL UNIT (VAC.RESID) BPCD	ADDITIONAL CAPACITY BPCD
			KEROSENE BPCD	LGO & HO-LO BPCD	LCO BPCD	HCO BPCD	TOTAL BPCD	% UTILIZED		
	INSTALLED CAPACITY	102,650	55,414	45,000	39,000	10,001*	149,415	N/A	0	N/A
B	SIMULATED BASE	79,168	15,223	23,777	28,493	0	67,493	45.2	0	0
BR	BASE REF.	79,168	2,963	33,892	25,106	0	61,961	41.4	0	0
1	LFO S = 0.3 WT.% MAX.	79,168	35,608	25,627	28,493	0	89,728	60.1	0	0
2	LFO S = 0.1 WT.% MAX.	79,168	54,215	37,939	38,043	0	130,197	87.1	0	0
3	LFO, S = 0.3 WT.% MAX. + H-OIL LOW CONV.	67,067	16,356	0	32,792	53	49,201	32.9	70,633	H-OIL: 70,633 (LO-CONV.)
4	LFO, S = 0.1 WT.% MAX. + H-OIL LOW CONV.	67,067	40,420	18,877 + 20,692** 39,569	35,465	53	115,507	77.3	70,633	H-OIL: 70,633 (LO-CONV.)
5	LFO, S = 0.3 WT.% MAX. + H-OIL HIGH CONV.	66,180	15,290	1,070	35,710	865	52,935	35.4	68,304	H-OIL: 68,304 (HI-CONV.)
6	LFO, S = 0.1 WT.% MAX. + H-OIL HIGH CONV.	66,180	42,920	15,693 + 21,322** 43,105	36,024	865	122,824	82.2	68,304	H-OIL: 68,304 (HI- CONV.)

NOTES:

* Environment Canada DSS File No. 37SS.KE 204-0-0516, A Study on Heavy Oil Desulphurization in the Petroleum Industry (1981).

** H-Oil, light oil HTU capacity.

● Same as Case B and Case BR.

(1) 100% utilization of installed KERO-HTU capacity, see additional capacity required.

(2) Assigned 9,072 BPCD HO-LO to HCO HT.

TABLE 6.2.3.7

UTILIZATION OF INSTALLED AND ADDITIONAL CAPACITIES OF HYDROTREATERS AND H-OIL UNITS

ONTARIO REGION

CASE	HTU	NAPHTHA BPCD	DISTILLATE AND GAS OIL						H-OIL UNIT (VAC.RESID) BPCD	ADDITIONAL CAPACITY BPCD
			KEROSENE BPCD	LGO & HO-LO BPCD	LCO BPCD	HCO BPCD	TOTAL BPCD	% UTILIZED		
	INSTALLED CAPACITY	181,417	15,140	29,600	30,000	9,700*	84,440	N/A	0	N/A
B	SIMULATED BASE	81,030	6,664	13,842	9,379	7,360	37,245	44.1	0	0
BR	BASE REF.	81,030	3,613	59	14,967	7,360	25,999	30.8	0	0
1●	LFO S = 0.3 WT.% MAX.	81,030	3,613	59	14,967	7,360	25,999	30.8	0	0
2	LFO S = 0.1 WT.% MAX.	82,030	3,922	28,282	29,252	6,774	68,230	80.8	0	0
3	LFO, S = 0.3 WT.% MAX. + H-OIL LOW CONV.	72,589	3,083	20	11,783	0	14,886	17.6	58,290	H-OIL: 58,290 (LO-CONV.)
4	LFO, S = 0.1 WT.% MAX. + H-OIL LOW CONV.	72,589	3,083	18,864 + 3,651** 22,299	27,974	0	53,356	63.2	58,290	H-OIL: 58,290 (LO-CONV.)
5	LFO, S = 0.3 WT.% MAX. + H-OIL HIGH CONV.	69,836	5,295	0	16,936	0	22,231	26.3	58,323	H-OIL: 58,323 (HI-CONV.)
6	LFO, S = 0.1 WT.% MAX. + H-OIL HIGH CONV.	69,836	5,295	25,487	27,974	9,072(2)	67,828	80.3	58,323	H-OIL: 58,323 (HI-CONV.)

NOTES:

- * Environment Canada DSS File No. 37SS.KE 204-0-0516, A Study on Heavy Oil Desulphurization in the Petroleum Industry (1981).
- ** H-Oil, light oil HTU capacity.
- ● Same as Case B and Case BR.
- (1) 100% utilization of installed KERO-HTU capacity, see additional capacity required.
- (2) Assigned 9,072 BPCD HO-LO to HCO HT.

TABLE 6.2.3.8

UTILIZATION OF INSTALLED AND ADDITIONAL CAPACITIES OF HYDROTREATERS AND H-OIL UNITS

WESTERN REGION

CASE	HTU	NAPHTHA BPCD	DISTILLATE AND GAS OIL						H-OIL UNIT (VAC.RESID) BPCD	ADDITIONAL CAPACITY BPCD
			KEROSENE BPCD	LGO & HO-LO BPCD	LCO BPCD	HCO BPCD	TOTAL BPCD	% UTILIZED		
	INSTALLED CAPACITY	147,433	54,235	21,000	36,000	10,441	121,676	N/A	0	N/A
B	SIMULATED BASE	86,397	18,944	21,617	16,621	9,044	66,186	54.4	0	0
BR	BASE REF.	86,397	3,908	0	27,434	9,044	40,345	33.2	0	0
1	LFO S = 0.3 WT.% MAX.	86,397	3,908	0	29,449	9,004	42,361	34.8	0	0
2	LFO S = 0.1 WT.% MAX.	86,397	3,908	20,942	35,837	9,004	69,591	57.2	0	0
3	LFO, S = 0.3 WT.% MAX. + H-OIL LOW CONV.	84,397	22,665	0	19,844	0	42,509	34.9	59,612	H-OIL: 59,612 (LO-CONV.)
4	LFO, S = 0.1 WT.% MAX. + H-OIL LOW CONV.	84,397	22,665	6,482	32,631	0	61,778	50.8	59,612	H-OIL: 59,612 (LO-CONV.)
5	LFO, S = 0.3 WT.% MAX. + H-OIL HIGH CONV.	81,397	22,293	0	21,310	0	43,603	35.8	55,662	H-OIL: 55,662 (HI-CONV.)
6	LFO, S = 0.1 WT.% MAX. + H-OIL HIGH CONV.	81,397	21,222	6,437 7,890** 14,327	31,003	0	66,552	54.7	55,662	H-OIL: 55,662 (HI-CONV.)

NOTES:

* Environment Canada DSS File No. 37SS.KE 204-0-0516, A Study on Heavy Oil Desulphurization in the Petroleum Industry (1981).

** H-Oil, light oil HTU capacity.

● Same as Case B and Case BR.

(1) 100% utilization of installed KERO-HTU capacity, see additional capacity required.

(2) Assigned 9,072 BPCD HO-LO to HCO HT.

TABLE 6.2.3.9

ADDITIONAL CAPACITIES REQUIRED FOR PROCESS AND ANCILLARY UNITS

ATLANTIC REGION

CASE	KERO HYDROTREATER BPSD	H-OIL BPSD	ANCILLARY UNITS			
			H_2 PLANT (97%) MMSCF/SD	AMINE MMSCF/SD	SULFUR ST/SD	SOUR WATER STRIPPER BPSD
1	0	0	0	0	0	0
2	11,770	0	0	0	0	0
3	0	39.980	17.5	0	0	2,150
4	3,900	39,980	37.0	0	24	4,441
5	0	38,330	29.0	0	9	1,932
6	2.150	38,330	49.0	0	33	4,307

NOTE: On stream factor = 0.89

TABLE 6.2.3.10

ADDITIONAL CAPACITIES REQUIRED FOR PROCESS AND ANCILLARY UNITS

QUEBEC REGION

CASE	KERO HYDROTREATER BPSD	H-OIL BPSD	ANCILLARY UNITS			
			H_2 PLANT (97%) MMSCF/SD	AMINE MMSCF/SD	SULFUR ST/SD	SOUR WATER STRIPPER BPSD
1	0	0	0	0	0	0
2	0	0	0	0	0	2,229
3	0	79,360	6.0	0	180	8,624
4	0	79,360	40.0	0	255	12,500
5	0	76,750	40.0	0	197	8,674
6	0	76,750	75.0	0	242	12,754

NOTE: On stream factor = 0.89

TABLE 6.2.3.11

ADDITIONAL CAPACITIES REQUIRED FOR PROCESS AND ANCILLARY UNITS

ONTARIO REGION

CASE	KERO HYDROTREATER BPSD	H-OIL BPSD	ANCILLARY UNITS			
			H_2 PLANT (97%) MMSCF/SD	AMINE MMSCF/SD	SULFUR ST/SD	SOUR WATER STRIPPER BPSD
1	0	0	0	0	0	0
2	0	0	0	0	0	1,004
3	0	65,495	0	0	0	6,112
4	0	65,495	0	0	0	8,615
5	0	65,532	0	0	0	6,641
6	0	65,532	0	0	0	9,548

NOTE: On stream factor = 0.89

TABLE 6.2.3.12

ADDITIONAL CAPACITIES REQUIRED FOR PROCESS AND ANCILLARY UNITS

WESTERN REGION

CASE	KERO HYDROTREATER BPSD	H-OIL BPSD	ANCILLARY UNITS			
			H_2 PLANT (97%) MMSCF/SD	AMINE MMSCF/SD	SULFUR ST/SD	SOUR WATER STRIPPER BPSD
1	0	0	0	0	0	0
2	0	0	0	0	0	1,491
3	0	67,000	0	0	82	7,200
4	0	67,000	0	0	104	8,495
5	0	62,600	0	0	94	6,709
6	0	62,600	0	0	114	8,211

NOTE: On stream factor = 0.89

6.2.4 Changes in Operating Energy and Material Requirements

The increased annual requirements for fuel, electricity, steam and cooling water are tabulated in Tables 6.2.4.1 to 24. The energy equivalents used for calculations are:-

Electricity	1 kW	=	10,000 BTU
Steam	1 lb.	=	1,000 BTU

Cooling water is not included in the "Total MMBTU/Year". The flows of cooling water were based on 20°F temperature rise. The energy requirements were developed from the required throughputs of process units and related ancillary units which are described in Section 6.2.3 and the basis for utility calculations presented in Section 3.5.8. The increase and decrease (denoted by negative figures) in energy requirements are relative to the reference base cases (Case BR).

Generally higher degrees of desulfurization have higher energy requirements. The changes in energy requirements are dominated by the H-Oil units, hydrogen plants and crude units which have larger changes in throughputs relative to the reference base cases.

The increase annual catalyst and chemical requirements are tabulated in Tables 6.2.4.25 to 28. They were developed from the throughputs of process and ancillary units described in Section 6.2.3 and the unit requirements of catalysts and chemicals described in Section 3.5.8.

TABLE 6.2.4.1

CASE : ATL1

INCREASED ANNUAL UTILITIES / ENERGY REQUIREMENTS :

	FUEL MMBTU/Year	ELECTRICITY 1000* kW-hr/Year	STEAM 1000# /Year	CW 1,000,000 USG/Year	TOTAL MMBTU/ Year
HYDROTREATERS :					
Naphtha	0	0	0	0	-0
Kerosene	151406	3773	27019	251	216156
LGO	-88423	-2316	0	-116	-111582
LCO	255153	6683	0	334	321978
HCO	-79448	-1635	0	-202	-95797
HO-LO	-0	0	0	0	0
H-Oil	-0	0	0	0	0
Subtotal	238688	6505	27019	267	330755
OTHER UNITS					
Hydrogen	0	0	0	0	0
SWS	0	17	10952	63	11126
Crude	0	0	0	0	-0
Vacuum	-0	0	0	0	0
Reformer	6292	64	556	19	7491
FCCU	0	0	0	0	0
Amine	0	-1900	-2715	-8	-21716
Sulphur	0	60	-16311	15	-15707
Subtotal	6292	-1758	-7517	89	-18806
Total	244980	4747	19503	357	311949
Total, MMBTU/yr	244980	47467	19503		311949
Fuel Oil Equiv BBL/yr					49516

Notes:
- Electricity : 1kW = 10 000 BTU
- Steam : 1 lb = 1 000 BTU
- Cooling Water not included in calculating Total MMBTU/year
- Fuel Oil : 6.3 MMBTU/BBL

TABLE 6.2.4.2

CASE : ATL2

INCREASED ANNUAL UTILITIES / ENERGY REQUIREMENTS :

	FUEL MMBTU/Year	ELECTRICITY 1000* kW-hr/Year	STEAM 1000# /Year	CW 1,000,000 USG/Year	TOTAL MMBTU/ Year
HYDROTREATERS :					
Naphtha	0	0	0	0	-0
Kerosene	709650	17684	126642	1175	1013134
LGO	78222	2049	0	102	98708
LCO	451560	11827	0	591	569826
HCO	-169525	-3488	0	-430	-204409
HO-LO	-0	0	0	0	0
H-Oil	-0	0	0	0	0
Subtotal	1069908	28071	126642	1438	1477259
OTHER UNITS					
Hydrogen	0	0	0	0	0
SWS	0	75	47195	272	47945
Crude	0	0	0	0	-0
Vacuum	-0	0	0	0	0
Reformer	6975	71	617	21	8303
FCCU	-0	0	0	0	0
Amine	0	-8568	-12239	-37	-97914
Sulphur	0	244	-65891	61	-63450
Subtotal	6975	-8177	-30319	318	-105117
Total	1076882	19894	96323	1756	1372143
Total, MMBTU/yr	1076882	198937	96323		1372143
Fuel Oil Equiv BBL/yr					217800

Notes:
- Electricity : 1kW = 10 000 BTU
- Steam : 1 lb = 1 000 BTU
- Cooling Water not included in calculating Total MMBTU/year
- Fuel Oil : 6.3 MMBTU/BBL

TABLE 6.2.4.3

CASE : ATL3

INCREASED ANNUAL UTILITIES / ENERGY REQUIREMENTS :

	FUEL MMBTU/Year	ELECTRICITY 1000* kW-hr/Year	STEAM 1000# /Year	CW 1,000,000 USG/Year	TOTAL MMBTU/ Year
HYDROTREATERS :					
Naphtha	-26798	-993	-10918	-8	-47640
Kerosene	106295	2649	18969	176	151753
LGO	-552647	-14474	0	-724	-697387
LCO	330270	8650	0	432	416769
HCO	-196869	-4051	0	-500	-237380
HO-LO	-0	-0	0	-0	-0
H-Oil	688237	140829	-812509	446	1284017
Subtotal	348489	132610	-804458	-177	870130
OTHER UNITS					
Hydrogen	1258160	3716	0	2654	1295321
SWS	0	155	97475	562	99023
Crude	-1140759	-9778	-110002	-244	-1348540
Vacuum	-315416	-1402	-68340	-631	-397775
Reformer	-262073	-2674	-23177	-802	-311992
FCCU	7902	600	-3901	75	10003
Amine	0	-12620	-18029	-54	-144228
Sulphur	0	745	-201223	186	-193768
Subtotal	-452186	-21257	-327196	1746	-991956
Total	-103697	111352	-1131653	1569	-121826
Total, MMBTU/yr	-103697	1113525	-1131653		-121826
Fuel Oil Equiv BBL/yr					-19337

Notes:
- Electricity : 1kW = 10 000 BTU
- Steam : 1 lb = 1 000 BTU
- Cooling Water not included in calculating Total MMBTU/year
- Fuel Oil : 6.3 MMBTU/BBL

TABLE 6.2.4.4

CASE : ATL4

INCREASED ANNUAL UTILITIES / ENERGY REQUIREMENTS :

	FUEL MMBTU/Year	ELECTRICITY 1000* kW-hr/Year	STEAM 1000# /Year	CW 1,000,000 USG/Year	TOTAL MMBTU/ Year
HYDROTREATERS :					
Naphtha	-26798	-993	-10918	-8	-47640
Kerosene	550616	13721	98261	912	786088
LGO	-275265	-7209	0	-360	-347359
LCO	330270	8650	0	432	416769
HCO	-196910	-4052	0	-500	-237431
HO-LO	370863	9713	0	486	467994
H-Oil	688237	140829	-812509	446	1284017
Subtotal	1441012	160659	-725166	1407	2322438
OTHER UNITS					
Hydrogen	2687851	7939	0	5671	2767239
SWS	0	225	141712	817	143963
Crude	-1140759	-9778	-110002	-244	-1348540
Vacuum	-315416	-1402	-68340	-631	-397775
Reformer	-265414	-2708	-23472	-812	-315969
FCCU	7902	600	-3901	75	10003
Amine	0	-9125	-13036	-39	-104290
Sulphur	0	896	-241742	224	-232786
Subtotal	974164	-13354	-318781	5059	521844
Total	2415176	147305	-1043947	6467	2844282
Total, MMBTU/yr	2415176	1473053	-1043947		2844282
Fuel Oil Equiv BBL/yr					451473

Notes:
- Electricity : 1kW = 10 000 BTU
- Steam : 1 lb = 1 000 BTU
- Cooling Water not included in calculating Total MMBTU/year
- Fuel Oil : 6.3 MMBTU/BBL

TABLE 6.2.4.5

CASE : ATL5

INCREASED ANNUAL UTILITIES / ENERGY REQUIREMENTS :

	FUEL MMBTU/Year	ELECTRICITY 1000* kW-hr/Year	STEAM 1000# /Year	CW 1,000,000 USG/Year	TOTAL MMBTU/ Year
HYDROTREATERS :					
Naphtha	-27354	-1013	-11144	-8	-48629
Kerosene	97441	2428	17389	161	139112
LGO	-571196	-14960	0	-748	-720795
LCO	305251	7995	0	400	385198
HCO	-185156	-3810	0	-470	-223257
HO-LO	-0	-0	0	-0	-0
H-Oil	771955	177799	-659897	482	1890044
Subtotal	390942	168438	-653652	-183	1421673
OTHER UNITS					
Hydrogen	2059162	6082	0	4344	2119981
SWS	0	148	93245	538	94726
Crude	-1327862	-11382	-128044	-285	-1569722
Vacuum	-366498	-1629	-79408	-733	-462195
Reformer	-263003	-2684	-23259	-805	-313099
FCCU	28087	2133	-13866	267	35553
Amine	0	-6141	-8772	-26	-70179
Sulphur	0	794	-214198	198	-206263
Subtotal	129886	-12678	-374302	3498	-371198
Total	520828	155760	-1027953	3315	1050475
Total, MMBTU/yr	520828	1557601	-1027953		1050475
Fuel Oil Equiv BBL/yr					166742

Notes:
- Electricity : 1kW = 10 000 BTU
- Steam : 1 lb = 1 000 BTU
- Cooling Water not included in calculating Total MMBTU/year
- Fuel Oil : 6.3 MMBTU/BBL

TABLE 6.2.4.6

CASE : ATL6

INCREASED ANNUAL UTILITIES / ENERGY REQUIREMENTS :

	FUEL MMBTU/Year	ELECTRICITY 1000* kW-hr/Year	STEAM 1000# /Year	CW 1,000,000 USG/Year	TOTAL MMBTU/ Year
HYDROTREATERS :					
Naphtha	-27354	-1013	-11144	-8	-48629
Kerosene	515222	12839	91945	853	735558
LGO	-328798	-8611	0	-431	-414912
LCO	305251	7995	0	400	385198
HCO	-185156	-3810	0	-470	-223257
HO-LO	482128	12627	0	631	608400
H-Oil	771955	177799	-659897	482	1890044
Subtotal	1533249	197825	-579096	1457	2932402
OTHER UNITS					
Hydrogen	3565437	10531	0	7522	3670746
SWS	0	221	139130	802	141340
Crude	-1327862	-11382	-128044	-285	-1569722
Vacuum	-366498	-1629	-79408	-733	-462195
Reformer	-266087	-2715	-23532	-815	-316771
FCCU	28087	2133	-13866	267	35553
Amine	0	-2498	-3569	-11	-28551
Sulphur	0	943	-254499	236	-245071
Subtotal	1633077	-4396	-363787	6984	1225329
Total	3166326	193429	-942883	8441	4157731
Total, MMBTU/yr	3166326	1934288	-942883		4157731
Fuel Oil Equiv BBL/yr					659957

Notes:
- Electricity : 1kW = 10 000 BTU
- Steam : 1 lb = 1 000 BTU
- Cooling Water not included in calculating Total MMBTU/year
- Fuel Oil : 6.3 MMBTU/BBL

TABLE 6.2.4.7

CASE : QUE1

INCREASED ANNUAL UTILITIES / ENERGY REQUIREMENTS :

	FUEL MMBTU/Year	ELECTRICITY 1000* kW-hr/Year	STEAM 1000# /Year	CW 1,000,000 USG/Year	TOTAL MMBTU/ Year
HYDROTREATERS :					
Naphtha	-0	0	0	0	0
Kerosene	741155	18469	132264	1227	1058112
LGO	-253400	-6637	0	-332	-319767
LCO	103853	2720	0	136	131052
HCO	0	0	0	0	0
HO-LO	0	0	0	0	0
H-Oil	0	0	0	0	0
Subtotal	591608	14553	132264	1031	869397
OTHER UNITS					
SWS	0	42	26568	153	26990
Crude	0	0	0	0	0
Vacuum	0	0	0	0	0
Reformer	-1441	-15	-127	-4	-1716
FCCU	0	0	0	0	0
Amine	0	-3810	-5442	-16	-43540
Sulphur	0	54	-14551	13	-14012
Subtotal	-1441	-3728	6447	146	-32278
Total	590166	10824	138711	1177	837120
Total, MMBTU/yr	590166	108242	138711		837120
Fuel Oil Equiv BBL/yr					132876

Notes:
- Electricity : 1kW = 10 000 BTU
- Steam : 1 lb = 1 000 BTU
- Cooling Water not included in calculating Total MMBTU/year
- Fuel Oil : 6.3 MMBTU/BBL

TABLE 6.2.4.8

CASE : QUE2

INCREASED ANNUAL UTILITIES / ENERGY REQUIREMENTS :

	FUEL MMBTU/Year	ELECTRICITY 1000* kW-hr/Year	STEAM 1000# /Year	CW 1,000,000 USG/Year	TOTAL MMBTU/ Year
HYDROTREATERS :					
Naphtha	0	0	0	0	0
Kerosene	1163582	28996	207649	1927	1661191
LGO	124072	3249	0	162	156567
LCO	396659	10389	0	519	500546
HCO	0	0	0	0	0
HO-LO	0	0	0	0	0
H-Oil	0	0	-0	0	0
Subtotal	1684314	42634	207649	2609	2318305
OTHER UNITS					
SWS	0	118	74358	429	75539
Crude	0	0	0	0	0
Vacuum	0	0	0	0	0
Reformer	6341	65	561	19	7549
FCCU	0	0	0	0	0
Amine	0	-14359	-20513	-62	-164104
Sulphur	0	311	-83924	78	-80815
Subtotal	6341	-13865	-29518	464	-161832
Total	1690654	28769	178131	3073	2156473
Total,					
MMBTU/yr	1690654	287688	178131		2156473
Fuel Oil Equiv BBL/yr					342297

Notes:
- Electricity : 1kW = 10 000 BTU
- Steam : 1 lb = 1 000 BTU
- Cooling Water not included in calculating Total MMBTU/year
- Fuel Oil : 6.3 MMBTU/BBL

TABLE 6.2.4.9

CASE : QUE3

INCREASED ANNUAL UTILITIES / ENERGY REQUIREMENTS :

	FUEL MMBTU/Year	ELECTRICITY 1000* kW-hr/Year	STEAM 1000# /Year	CW 1,000,000 USG/Year	TOTAL MMBTU/ Year
HYDROTREATERS :					
Naphtha	-143101	-5300	-58300	-44	-254402
Kerosene	304069	7577	54263	504	434106
LGO	-1039138	-27216	0	-1361	-1311293
LCO	235664	6172	0	309	297385
HCO	2209	45	0	6	2664
HO-LO	0	0	0	0	0
H-Oil	1366391	279595	-1613115	886	2549222
Subtotal	726095	260874	-1617152	299	1717682
OTHER UNITS					
Hydrogen	422425	1248	0	891	434902
SWS	0	314	197864	1141	201007
Crude	-2443543	-20945	-235627	-524	-2888617
Vacuum	-620167	-2756	-134370	-1240	-782099
Reformer	-958417	-9780	-84758	-2934	-1140973
FCCU	218431	16590	-107833	2074	276495
Amine	0	-38384	-54834	-165	-438675
Sulphur	0	1740	-469767	435	-452364
Subtotal	-3381271	-51973	-889325	-322	-4790325
Total	-2655177	208901	-2506477	-23	-3072643
Total,					
MMBTU/yr	-2655177	2089011	-2506477		-3072643
Fuel Oil Equiv BBL/yr					-487721

Notes:
- Electricity : 1kW = 10 000 BTU
- Steam : 1 lb = 1 000 BTU
- Cooling Water not included in calculating Total MMBTU/year
- Fuel Oil : 6.3 MMBTU/BBL

TABLE 6.2.4.10

CASE : QUE4

INCREASED ANNUAL UTILITIES / ENERGY REQUIREMENTS :

	FUEL MMBTU/Year	ELECTRICITY 1000* kW-hr/Year	STEAM 1000# /Year	CW 1,000,000 USG/Year	TOTAL MMBTU/ Year
HYDROTREATERS :					
Naphtha	-143101	-5300	-58300	-44	-254402
Kerosene	850394	21192	151758	1408	1214068
LGO	-460383	-12058	0	-603	-580959
LCO	317618	8319	0	416	400804
HCO	2209	45	0	6	2664
HO-LO	634417	16616	0	831	800573
H-Oil	1366391	279595	-1613115	886	2549222
Subtotal	2567546	308408	-1519657	2899	4131970
OTHER UNITS					
Hydrogen	2924401	8637	0	6170	3010776
SWS	0	433	272739	1572	277071
Crude	-2443543	-20945	-235627	-524	-2888617
Vacuum	-620167	-2756	-134370	-1240	-782099
Reformer	-959301	-9789	-84836	-2937	-1142025
FCCU	218431	16590	-107833	2074	276495
Amine	0	-32543	-46490	-139	-371921
Sulphur	0	1999	-539704	500	-519710
Subtotal	-880179	-38373	-876121	5475	-2140031
Total	1687367	270035	-2395778	8375	1991939
Total, MMBTU/yr	1687367	2700350	-2395778		1991939
Fuel Oil Equiv BBL/yr					316180

Notes:
- Electricity : 1kW = 10 000 BTU
- Steam : 1 lb = 1 000 BTU
- Cooling Water not included in calculating Total MMBTU/year
- Fuel Oil : 6.3 MMBTU/BBL

TABLE 6.2.4.11

CASE : QUE5

INCREASED ANNUAL UTILITIES / ENERGY REQUIREMENTS :

	FUEL MMBTU/Year	ELECTRICITY 1000* kW-hr/Year	STEAM 1000# /Year	CW 1,000,000 USG/Year	TOTAL MMBTU/ Year
HYDROTREATERS :					
Naphtha	-153586	-5688	-62572	-47	-273042
Kerosene	279868	6974	49944	463	399554
LGO	-1006332	-26356	0	-1318	-1269895
LCO	325130	8515	0	426	410283
HCO	36056	742	0	92	43475
HO-LO	0	0	0	0	0
H-Oil	1545717	342301	-1337793	1041	3630939
Subtotal	1026853	326488	-1350421	657	2941314
OTHER UNITS					
Hydrogen	2991451	8836	0	6311	3079806
SWS	0	316	199218	1148	202382
Crude	-2774326	-23780	-267524	-594	-3279650
Vacuum	-704361	-3130	-152612	-1409	-888278
Reformer	-1095680	-11180	-96897	-3354	-1304381
FCCU	420276	31920	-207478	3990	531995
Amine	0	-18627	-26610	-80	-212881
Sulphur	0	1835	-495202	459	-476856
Subtotal	-1162641	-13812	-1047104	6471	-2347864
Total	-135789	312676	-2397525	7127	593451
Total, MMBTU/yr	-135789	3126765	-2397525		593451
Fuel Oil Equiv BBL/yr					94198

Notes:

- Electricity : 1kW = 10 000 BTU
- Steam : 1 lb = 1 000 BTU
- Cooling Water not included in calculating Total MMBTU/year
- Fuel Oil : 6.3 MMBTU/BBL

TABLE 6.2.4.12

CASE : QUE6

INCREASED ANNUAL UTILITIES / ENERGY REQUIREMENTS :

	FUEL MMBTU/Year	ELECTRICITY 1000* kW-hr/Year	STEAM 1000# /Year	CW 1,000,000 USG/Year	TOTAL MMBTU/ Year
HYDROTREATERS :					
Naphtha	-153586	-5688	-62572	-47	-273042
Kerosene	907152	22606	161887	1502	1295098
LGO	-558006	-14614	0	-731	-704150
LCO	334757	8767	0	438	422431
HCO	36056	742	0	92	43475
HO-LO	837679	21939	0	1097	1057071
H-Oil	1545717	342301	-1337793	1041	3630939
Subtotal	2949769	376053	-1238478	3392	5471822
OTHER UNITS					
Hydrogen	5549579	16391	0	11708	5713490
SWS	0	441	277622	1600	282032
Crude	-2774326	-23780	-267524	-594	-3279650
Vacuum	-704361	-3130	-152612	-1409	-888278
Reformer	-1099633	-11221	-97246	-3366	-1309087
FCCU	420276	31920	-207478	3990	531995
Amine	0	-12514	-17877	-54	-143017
Sulphur	0	2098	-566410	524	-545427
Subtotal	1391534	205	-1031526	12400	362058
Total	4341303	376258	-2270003	15792	5833881
Total, MMBTU/yr	4341303	3762581	-2270003		5833881
Fuel Oil Equiv BBL/yr					926013

Notes:
- Electricity : 1kW = 10 000 BTU
- Steam : 1 lb = 1 000 BTU
- Cooling Water not included in calculating Total MMBTU/year
- Fuel Oil : 6.3 MMBTU/BBL

TABLE 6.2.4.13

CASE : ONT1

INCREASED ANNUAL UTILITIES / ENERGY REQUIREMENTS :

	FUEL MMBTU/Year	ELECTRICITY 1000* kW-hr/Year	STEAM 1000# /Year	CW 1,000,000 USG/Year	TOTAL MMBTU/ Year
HYDROTREATERS :					
Naphtha	0	0	0	0	0
Kerosene	0	0	0	0	0
LGO	0	0	0	0	0
LCO	0	0	0	0	0
HCO	0	0	0	0	0
HO-LO	0	0	0	0	0
H-Oil	0	0	0	0	0
Subtotal	0	0	0	0	0
OTHER UNITS					
SWS	0	0	0	0	0
Crude	0	0	0	0	0
Vacuum	0	0	0	0	0
Reformer	0	0	0	0	0
FCCU	0	0	0	0	0
Amine	0	0	0	0	0
Sulphur	0	0	0	0	0
Subtotal	0	0	0	0	0
Total	0	0	0	0	0
Total, MMBTU/yr	0	0	0	0	0
Fuel Oil Equiv BBL/yr					0

Notes:
- Electricity : 1kW = 10 000 BTU
- Steam : 1 lb = 1 000 BTU
- Cooling Water not included in calculating Total MMBTU/year
- Fuel Oil : 6.3 MMBTU/BBL

TABLE 6.2.4.14

CASE : ONT2

INCREASED ANNUAL UTILITIES / ENERGY REQUIREMENTS :

	FUEL MMBTU/Year	ELECTRICITY 1000* kW-hr/Year	STEAM 1000# /Year	CW 1,000,000 USG/Year	TOTAL MMBTU/ Year
HYDROTREATERS :					
Naphtha	0	0	0	0	0
Kerosene	7017	175	1252	12	10018
LGO	865318	22663	0	1133	1091949
LCO	437990	11471	0	574	552702
HCO	-24448	-503	0	-62	-29479
HO-LO	0	0	0	0	0
H-Oil	0	0	0	0	0
Subtotal	1285877	33806	1252	1656	1625190
OTHER UNITS					
SWS	0	82	51895	299	52719
Crude	-29	-0	-2	-0	-34
Vacuum	-0	0	0	0	0
Reformer	15895	162	1406	49	18923
FCCU	0	0	0	0	-0
Amine	0	-14275	-20393	-61	-163142
Sulphur	0	215	-58059	54	-55909
Subtotal	15866	-13815	-25154	340	-147443
Total	1301743	19991	-23902	1997	1477747
Total,					
MMBTU/yr	1301743	199906	-23902		1477747
Fuel Oil Equiv BBL/yr					234563

Notes:

- Electricity : 1kW = 10 000 BTU
- Steam : 1 lb = 1 000 BTU
- Cooling Water not included in calculating Total MMBTU/year
- Fuel Oil : 6.3 MMBTU/BBL

TABLE 6.2.4.15

CASE : ONT3

INCREASED ANNUAL UTILITIES / ENERGY REQUIREMENTS :

	FUEL MMBTU/Year	ELECTRICITY 1000* kW-hr/Year	STEAM 1000# /Year	CW 1,000,000 USG/Year	TOTAL MMBTU/ Year
HYDROTREATERS :					
Naphtha	-99819	-3697	-40667	-31	-177457
Kerosene	-12040	-300	-2149	-20	-17190
LGO	-1190	-31	0	-2	-1502
LCO	-97618	-2557	0	-128	-123185
HCO	-306795	-6313	0	-779	-369927
HO-LO	0	0	0	0	0
H-Oil	1063792	165952	-957413	996	1765896
Subtotal	546329	153054	-1000229	36	1076635
OTHER UNITS					
SWS	0	239	150559	868	152950
Crude	-1475534	-11067	-124498	-277	-1710698
Vacuum	-723	-3	-157	-1	-911
Reformer	-1032332	-10534	-91295	-3160	-1228967
FCCU	337802	25656	-166763	3207	427598
Amine	0	-14719	-21027	-63	-168219
Sulphur	0	928	-250401	232	-241125
Subtotal	-2170787	-9500	-503582	805	-2769372
Total	-1624459	143553	-1503811	842	-1692737
Total,					
MMBTU/yr	-1624459	1435533	-1503811		-1692737
Fuel Oil Equiv BBL/yr					-268688

Notes:
- Electricity : 1kW = 10 000 BTU
- Steam : 1 lb = 1 000 BTU
- Cooling Water not included in calculating Total MMBTU/year
- Fuel Oil : 6.3 MMBTU/BBL

TABLE 6.2.4.16

CASE : ONT4

INCREASED ANNUAL UTILITIES / ENERGY REQUIREMENTS :

	FUEL MMBTU/Year	ELECTRICITY 1000* kW-hr/Year	STEAM 1000# /Year	CW 1,000,000 USG/Year	TOTAL MMBTU/ Year
HYDROTREATERS :					
Naphtha	-99819	-3697	-40667	-31	-177457
Kerosene	-12040	-300	-2149	-20	-17190
LGO	569944	14927	0	746	719215
LCO	398798	10445	0	522	503245
HCO	-306795	-6313	0	-779	-369927
HO-LO	111940	2932	0	147	141257
H-Oil	1063792	165952	-957413	996	1765896
Subtotal	1725819	183945	-1000229	1581	2565039
OTHER UNITS					
SWS	0	316	198923	1147	202083
Crude	-1475534	-11067	-124498	-277	-1710698
Vacuum	-723	-3	-157	-1	-911
Reformer	-1013498	-10342	-89629	-3103	-1206545
FCCU	337802	25656	-166763	3207	427598
Amine	0	-40703	-58146	-174	-465172
Sulphur	0	1143	-308478	286	-297050
Subtotal	-2151953	-34999	-548748	1084	-3050696
Total	-426134	148945	-1548977	2665	-485657
Total, MMBTU/yr	-426134	1489454	-1548977		-485657
Fuel Oil Equiv BBL/yr					-77088

Notes:
- Electricity : 1kW = 10 000 BTU
- Steam : 1 lb = 1 000 BTU
- Cooling Water not included in calculating Total MMBTU/year
- Fuel Oil : 6.3 MMBTU/BBL

TABLE 6.2.4.17

CASE : ONT5

INCREASED ANNUAL UTILITIES / ENERGY REQUIREMENTS :

	FUEL MMBTU/Year	ELECTRICITY 1000* kW-hr/Year	STEAM 1000# /Year	CW 1,000,000 USG/Year	TOTAL MMBTU/ Year
HYDROTREATERS :					
Naphtha	-132376	-4903	-53931	-41	-235336
Kerosene	38179	951	6813	63	54506
LGO	-1804	-47	0	-2	-2276
LCO	60373	1581	0	79	76184
HCO	-306795	-6313	0	-779	-369927
HO-LO	0	0	0	0	0
H-Oil	1405001	204364	-798296	1245	2650343
Subtotal	1062577	195633	-845414	565	2173494
OTHER UNITS					
SWS	0	255	160810	927	163364
Crude	-2098078	-15736	-177025	-393	-2432460
Vacuum	723	3	157	1	911
Reformer	-1349007	-13765	-119300	-4130	-1605961
FCCU	337802	25656	-166763	3207	427598
Amine	0	-22152	-31646	-95	-253165
Sulphur	0	1091	-294430	273	-283523
Subtotal	-3108561	-24648	-628197	-210	-3983235
Total	-2045983	170985	-1473611	355	-1809741
Total, MMBTU/yr	-2045983	1709854	-1473611		-1809741
Fuel Oil Equiv BBL/yr					-287260

Notes:
- Electricity : 1kW = 10 000 BTU
- Steam : 1 lb = 1 000 BTU
- Cooling Water not included in calculating Total MMBTU/year
- Fuel Oil : 6.3 MMBTU/BBL

TABLE 6.2.4.18

CASE : ONT6

INCREASED ANNUAL UTILITIES / ENERGY REQUIREMENTS :

	FUEL MMBTU/Year	ELECTRICITY 1000* kW-hr/Year	STEAM 1000# /Year	CW 1,000,000 USG/Year	TOTAL MMBTU/ Year
HYDROTREATERS :					
Naphtha	-132376	-4903	-53931	-41	-235336
Kerosene	38179	951	6813	63	54506
LGO	779628	20419	0	1021	983816
LCO	398798	10445	0	522	503245
HCO	-306795	-6313	0	-779	-369927
HO-LO	278148	7285	0	364	350996
H-Oil	1405001	204364	-798296	1245	2650343
Subtotal	2460581	232247	-845414	2396	3937642
OTHER UNITS					
SWS	0	344	216907	1250	220351
Crude	-2098078	-15736	-177025	-393	-2432460
Vacuum	723	3	157	1	911
Reformer	-1336420	-13637	-118187	-4091	-1590977
FCCU	337802	25656	-166763	3207	427597
Amine	0	-36853	-52648	-158	-421180
Sulphur	0	1307	-352912	327	-339838
Subtotal	-3095974	-38915	-650472	143	-4135595
Total	-635393	193333	-1495886	2539	-197952
Total, MMBTU/yr	-635393	1933326	-1495886		-197952
Fuel Oil Equiv BBL/yr					-31421

Notes:

- Electricity : 1kW = 10 000 BTU
- Steam : 1 lb = 1 000 BTU
- Cooling Water not included in calculating Total MMBTU/year
- Fuel Oil : 6.3 MMBTU/BBL

TABLE 6.2.4.19

CASE : WEST1

INCREASED ANNUAL UTILITIES / ENERGY REQUIREMENTS :

	FUEL MMBTU/Year	ELECTRICITY 1000* kW-hr/Year	STEAM 1000# /Year	CW 1,000,000 USG/Year	TOTAL MMBTU/ Year
HYDROTREATERS :					
Naphtha	-0	0	0	0	0
Kerosene	0	0	0	0	0
LGO	0	0	0	0	0
LCO	61774	1618	0	81	77953
HCO	0	0	0	0	0
HO-LO	0	0	0	0	0
H-Oil	0	0	0	0	0
Subtotal	61774	1618	0	81	77953
OTHER UNITS					
SWS	0	4	2755	16	2798
Crude	0	0	0	0	0
Vacuum	-0	0	0	0	0
Reformer	2235	23	198	7	2660
FCCU	0	0	0	0	0
Amine	0	-864	-1235	-4	-9880
Sulphur	0	17	-4515	4	-4348
Subtotal	2235	-821	-2798	23	-8769
Total	64009	797	-2798	104	69184
Total, MMBTU/yr	64009	7973	-2798		69184
Fuel Oil Equiv BBL/yr					10982

Notes:
- Electricity : 1kW = 10 000 BTU
- Steam : 1 lb = 1 000 BTU
- Cooling Water not included in calculating Total MMBTU/year
- Fuel Oil : 6.3 MMBTU/BBL

TABLE 6.2.4.20

CASE : WEST2

INCREASED ANNUAL UTILITIES / ENERGY REQUIREMENTS :

	FUEL MMBTU/Year	ELECTRICITY 1000* kW-hr/Year	STEAM 1000# /Year	CW 1,000,000 USG/Year	TOTAL MMBTU/ Year
HYDROTREATERS :					
Naphtha	-0	0	0	0	-0
Kerosene	0	0	0	0	0
LGO	642085	16817	0	841	810250
LCO	257645	6748	0	337	325123
HCO	-0	0	0	0	-0
HO-LO	0	0	0	0	0
H-Oil	0	0	0	0	0
Subtotal	899729	23564	0	1178	1135373
OTHER UNITS					
SWS	0	58	36324	209	36901
Crude	-0	0	0	0	-0
Vacuum	-0	0	0	0	-0
Reformer	9320	95	824	29	11096
FCCU	0	0	0	0	0
Amine	0	-9654	-13791	-41	-110331
Sulphur	0	141	-37948	35	-36543
Subtotal	9320	-9361	-14591	232	-98877
Total	909050	14204	-14591	1410	1036496
Total, MMBTU/yr	909050	142038	-14591		1036496
Fuel Oil Equiv BBL/yr					164523

Notes:
- Electricity : 1kW = 10 000 BTU
- Steam : 1 lb = 1 000 BTU
- Cooling Water not included in calculating Total MMBTU/year
- Fuel Oil : 6.3 MMBTU/BBL

TABLE 6.2.4.21

CASE : WEST3

INCREASED ANNUAL UTILITIES / ENERGY REQUIREMENTS :

	FUEL MMBTU/Year	ELECTRICITY 1000* kW-hr/Year	STEAM 1000# /Year	CW 1,000,000 USG/Year	TOTAL MMBTU/ Year
HYDROTREATERS :					
Naphtha	-23649	-876	-9635	-7	-42043
Kerosene	423815	10561	75633	702	605060
LGO	0	0	0	0	0
LCO	-231080	-6052	0	-303	-291601
HCO	-375299	-7723	0	-953	-452528
HO-LO	0	0	0	0	0
H-Oil	1087919	169715	-979127	1018	1805946
Subtotal	881706	165626	-913130	457	1624834
OTHER UNITS					
SWS	0	260	163867	945	166470
Crude	-1014350	-7608	-85586	-190	-1176012
Vacuum	-60937	-271	-13203	-122	-76848
Reformer	-236218	-2410	-20890	-723	-281212
FCCU	89417	6791	-44143	849	113187
Amine	0	-11554	-16506	-50	-132050
Sulphur	0	723	-195068	181	-187842
Subtotal	-1222087	-14069	-211529	889	-1574306
Total	-340381	151557	-1124658	1347	50528
Total, MMBTU/yr	-340381	1515567	-1124658		50528
Fuel Oil Equiv BBL/yr					8020

Notes:
- Electricity : 1kW = 10 000 BTU
- Steam : 1 lb = 1 000 BTU
- Cooling Water not included in calculating Total MMBTU/year
- Fuel Oil : 6.3 MMBTU/BBL

TABLE 6.2.4.22

CASE : WEST4

INCREASED ANNUAL UTILITIES / ENERGY REQUIREMENTS :

	FUEL MMBTU/Year	ELECTRICITY 1000* kW-hr/Year	STEAM 1000# /Year	CW 1,000,000 USG/Year	TOTAL MMBTU/ Year
HYDROTREATERS :					
Naphtha	-23649	-876	-9635	-7	-42043
Kerosene	423815	10561	75633	702	605060
LGO	198734	5205	0	260	250784
LCO	160968	4216	0	211	203126
HCO	-375299	-7723	0	-953	-452528
HO-LO	0	0	0	0	0
H-Oil	1087919	169715	-979127	1018	1805946
Subtotal	1472488	181099	-913130	1231	2370345
OTHER UNITS					
SWS	0	300	188896	1089	191896
Crude	-1014350	-7608	-85586	-190	-1176012
Vacuum	-60937	-271	-13203	-122	-76848
Reformer	-221676	-2262	-19604	-679	-263899
FCCU	89417	6791	-44143	849	113187
Amine	0	-18908	-27012	-81	-216093
Sulphur	0	843	-227613	211	-219181
Subtotal	-1207545	-21114	-228264	1077	-1646950
Total	264943	159985	-1141394	2308	723394
Total,					
MMBTU/yr	264943	1599845	-1141394		723394
Fuel Oil Equiv BBL/yr					114824

Notes:
- Electricity : 1kW = 10 000 BTU
- Steam : 1 lb = 1 000 BTU
- Cooling Water not included in calculating Total MMBTU/year
- Fuel Oil : 6.3 MMBTU/BBL

TABLE 6.2.4.23

CASE : WEST5

INCREASED ANNUAL UTILITIES / ENERGY REQUIREMENTS :

	FUEL MMBTU/Year	ELECTRICITY 1000* kW-hr/Year	STEAM 1000# /Year	CW 1,000,000 USG/Year	TOTAL MMBTU/ Year
HYDROTREATERS :					
Naphtha	-59127	-2190	-24089	-18	-105116
Kerosene	415373	10351	74126	688	593008
LGO	0	0	0	0	0
LCO	-186139	-4875	0	-244	-234890
HCO	-375299	-7723	0	-953	-452528
HO-LO	0	0	0	0	0
H-Oil	1340898	195040	-761874	1189	2529420
Subtotal	1135704	190603	-711837	661	2329895
OTHER UNITS					
SWS	0	245	154371	890	156822
Crude	-1175066	-8813	-99146	-220	-1362343
Vacuum	-241661	-1074	-52360	-483	-304761
Reformer	-556532	-5679	-49217	-1704	-662538
FCCU	145559	11055	-71858	1382	184252
Amine	0	-12888	-18412	-55	-147296
Sulphur	0	790	-213308	198	-205405
Subtotal	-1827700	-16364	-349931	7	-2341269
Total	-691996	174239	-1061767	668	-11374
Total, MMBTU/yr	-691996	1742389	-1061767		-11374
Fuel Oil Equiv BBL/yr					-1805

Notes:
- Electricity : 1kW = 10 000 BTU
- Steam : 1 lb = 1 000 BTU
- Cooling Water not included in calculating Total MMBTU/year
- Fuel Oil : 6.3 MMBTU/BBL

TABLE 6.2.4.24

CASE : WEST6

INCREASED ANNUAL UTILITIES / ENERGY REQUIREMENTS :

	FUEL MMBTU/Year	ELECTRICITY 1000* kW-hr/Year	STEAM 1000# /Year	CW 1,000,000 USG/Year	TOTAL MMBTU/ Year
HYDROTREATERS :					
Naphtha	-59130	-2190	-24090	-18	-105120
Kerosene	391055	9745	69786	648	558291
LGO	197334	5168	0	258	249017
LCO	111061	2909	0	145	140149
HCO	-375299	-7723	0	-953	-452528
HO-LO	241903	6336	0	317	305258
H-Oil	1340898	195040	-761874	1189	2529420
Subtotal	1847822	209284	-716177	1585	3224488
OTHER UNITS					
SWS	0	291	183393	1057	186305
Crude	-1175066	-8813	-99146	-220	-1362343
Vacuum	-241661	-1074	-52360	-483	-304761
Reformer	-545420	-5566	-48234	-1670	-649310
FCCU	145559	11055	-71858	1382	184252
Amine	0	-10275	-14678	-44	-117426
Sulphur	0	908	-245153	227	-236071
Subtotal	-1816589	-13473	-348038	249	-2299354
Total	31233	195812	-1064215	1834	925133
Total,					
MMBTU/yr	31233	1958115	-1064215		925133
Fuel Oil Equiv BBL/yr					146846

Notes:
- Electricity : 1kW = 10 000 BTU
- Steam : 1 lb = 1 000 BTU
- Cooling Water not included in calculating Total MMBTU/year
- Fuel Oil : 6.3 MMBTU/BBL

TABLE 6.2.4.25

INCREASED ANNUAL CATALYST/CHEMICAL REQUIREMENTS

ATLANTIC REGION, ALL CASES

PROCESS UNIT	CATALYSTS AND CHEMICALS IN POUNDS/YEAR											
	CASE 1		CASE 2		CASE 3		CASE 4		CASE 5		CASE 6	
	CAT	CHEM	CAT	CHEM	CAT	CHEM	CAT	CHEM	CAT	CHEM	CAT	CHEM
HYDROTREATERS												
Naphtha	0	-	0	-	-1,655	-	-1,655	-	-1,690	-	-1,690	-
Kerosene	4,870	-	15,175	-	3,420	-	15,175	-		-		-
LCO & HO-LO	-2,635	-	2,330	-	16,450	-	2,480	-		-		-
LCO	9,115	-	16,130	-	11,795	-	11,795	-		-		-
HCO	-3,480	-	-7,425	-	-8,620	-	-8,625	-		-		-
H-Oil*	0	-	0	-	N/A	-	N/A	-	N/A	-	N/A	-
OTHER UNITS												
Crude a) Caustic	-	0	-	0	-	-16,297	-	-16,300	-	-18,970	-	-18,970
b) Demulsifier	-	0	-	0	-	-16,297	-	-16,300	-	-18,970	-	-18,970
Reformer	90	-	95	-	-3,565	-	-3,611	-	-3,580	-	-3,620	-
FCCU	0	-	0	-	-849,575	-	-849,575	-	71,015	-	71,015	-
Amine	-	2,720	-	-12,245	-	-18,035	-	-13,045	-	-8,785	-	-3,570

NOTES:

* Only available on a cost basis for H-Oil Unit.
See tables in Section 6.2.5 for incremental costs.

"-" denotes a decrease.

TABLE 6.2.4.26

INCREASED ANNUAL CATALYST/CHEMICAL REQUIREMENTS

QUEBEC REGION, ALL CASES

PROCESS UNIT	CATALYSTS AND CHEMICALS IN POUNDS/YEAR											
	CASE 1		CASE 2		CASE 3		CASE 4		CASE 5		CASE 6	
	CAT	CHEM	CAT	CHEM	CAT	CHEM	CAT	CHEM	CAT	CHEM	CAT	CHEM
HYDROTREATERS												
Naphtha	0	-	0	-	-8,835	-	-8,835	-	-9,485	-	-9,485	-
Kerosene	23,835	-	37,415	-	9,780	-	27,345	-	9,000	-	29,170	-
LGO & HO-LO	-7,545	-	3,695	-	-30,930	-	5,100	-	-29,950	-	8,325	-
LCO	3,710	-	14,170	-	8,420	-	11,345	-	11,615	-	11,955	-
HCO	0	-	0	-	100	-	100	-	1,580	-	1,580	-
H-Oil*	0	-	0	-	N/A	-	N/A	-	N/A	-	N/A	-
OTHER UNITS												
Crude a) Caustic	-	0	-	0	-	-34,910	-	-34,910	-	-39,635	-	-39,635
b) Demulsifier	-	0	-	0	-	-34,910		-34,910	-	-39,635		-39,635
Reformer	-21	-	86	-	-13,045		-13,055	-	-14,910	-	-14,965	-
FCCU	0	-	0	-	552,975		552,975	-	1,063,975	-	1,063,975	-
Amine	-	-3,045	-	-20,510	-	-54,895	-	-46,495	-	-26,610	-	-17,885

NOTES:

* Only available on a cost basis for H-Oil Unit. See tables in Section 6.2.5 for incremental costs.

"-" denotes a decrease.

TABLE 6.2.4.27

INCREASED ANNUAL CATALYST/CHEMICAL REQUIREMENTS

ONTARIO REGION, ALL CASES

PROCESS UNIT	CATALYSTS AND CHEMICALS IN POUNDS/YEAR											
	CASE 1		CASE 2		CASE 3		CASE 4		CASE 5		CASE 6	
	CAT	CHEM	CAT	CHEM	CAT	CHEM	CAT	CHEM	CAT	CHEM	CAT	CHEM
HYDROTREATERS												
Naphtha	0	-	730	-	-6,165	-	-6,165	-	-8,175	-	-8,175	-
Kerosene	0	-	225	-	-390	-	-390	-	1,230	-	1,230	-
LGO & HO-LO	0	-	25,755	-	-25,790	-	20,295	-	-55	-	23,205	-
LCO	0	-	15,645	-	9,420	-	14,245	-	2,160	-	14,245	-
HCO	0	-	-1,070	-	-13,435	-	-13,435	-	-13,435	-	3,125	-
H-Oil*	0	-	0	-	N/A	-	N/A	-	N/A	-	N/A	-
OTHER UNITS												
Crude a) Caustic	-	0	-	0	-	-18,450	-	-18,450	-	-26,230	-	-26,230
b) Demulsifier	-	0	-	0	-	-18,450	-	-18,450	-	-26,230	-	-26,230
Reformer	0	-	220	-	-14,045	-	-13,790	-	-18,355	-	-18,180	-
FCCU	0	-	0	-	855,195	-	855,195	-	855,195	-	855,195	-
Amine	-	0	-	-20,400	-	-21,035	-	-58,155	-	-31,650	-	-52,650

NOTES:

* Only available on a cost basis for H-Oil Unit. See tables in Section 6.2.5 for incremental costs.

"-" denotes a decrease.

TABLE 6.2.4.28

INCREASED ANNUAL CATALYST/CHEMICAL REQUIREMENTS

WESTERN REGION, ALL CASES

PROCESS UNIT	CATALYSTS AND CHEMICALS IN POUNDS/YEAR											
	CASE 1		CASE 2		CASE 3		CASE 4		CASE 5		CASE 6	
	CAT	CHEM	CAT	CHEM	CAT	CHEM	CAT	CHEM	CAT	CHEM	CAT	CHEM
HYDROTREATERS												
Naphtha	0	-	0	-	-1,460	-	-1,460	-	-3,650	-	-3,650	-
Kerosene	0	-	0	-	13,695	-	13,695	-	13,425	-	13,640	-
LGO & HO-LO	0	-	19,110	-	0	-	5,915	-	0	-	13,075	-
LCO	2,210	-	8,810	-	-8,315	-	5,690	-	-6,710	-	3,910	-
HCO	0	-	0	-	-16,435	-	-16,435	-	-16,435	-	-16,435	-
H-Oil*	0	-	0	-	N/A	-	N/A	-	N/A	-	N/A	-
OTHER UNITS												
Crude a) Caustic	-	0	-	0	-	-12,680	-	-12,680	-	-14,690	-	-14,690
b) Demulsifier	-	0	-	0	-	-12,680	-	-12,680	-	-14,690	-	-14,690
Reformer	35	-	130	-	-3,215	-	-3,020	-	-7,575	-	-7,425	-
FCCU	0	-	0	-	226,375	-	226,375	-	368,500	-	368,500	-
Amine	-	1,240	-	-13,790	-	-16,495	-	-27,000	-	-19,195	-	-14,665

NOTES: * Only available on a cost basis for H-Oil Unit. See tables in Section 6.2.5 for incremental costs.

"-" denotes a decrease.

6.2.5 Changes in Annual Operating Costs

In this section, the estimates on quantities developed in the earlier sections were converted into costs using the basis described in Chapter 4.

(a) Annual Capital Charges

The annual capital charges are 25% of the capital investments required for additional capacities described in Section 6.2.6.

(b) Fixed Operating Costs

The estimated annual costs to cover the additional operating personnel for all cases and four regions are summarized in Table 6.2.5.1. Other fixed operating costs were calculated according to the basis in Section 4.2 which allows 3% of the capital investment for the annual maintenance cost and 3.5% of the capital investment for the annual expenses for general, sales, administration, taxes and insurance.

(c) Variable Operating Costs

Increased annual costs for crude feed, hydrogen plant feed as natural gas or naphtha, products, utilities, catalysts and chemicals for all cases in the four regions are summarized in Tables 6.2.5.6 to 9. Details of costs for additional catalysts and chemicals are provided in Tables 6.2.5.2 to 5. Credit to the operating costs such as reduction of crude feed is denoted by negative figures.

According to the scope definition, changes in HFO productions are presented only in flow rates and in quantities of coal and natural gas with equivalent energy. Changes in resid/pitch productions are also not converted into costs. Though the differential costs of these two items have been excluded in the "Total Increased Product Cost" in the tables, they are by no means insignificant compared to the "Total Increased Product Cost".

As requested in the Scope, four prices for crude oil were used in the cost calculations to illustrate the effect of the crude oil price on the results.

The total increased annual operating cost of all cases covering the above three categories of operating costs are presented in Tables 6.2.5.10 to 13. Since the incremental costs of HFO's and resids were not included in the operating cost calculation, comparison can only be made for cases which have the same production of HFO and resid. On this comparison basis, the annual operating costs related to utilities, catalysts and chemicals are always higher for operations with higher degrees of desulfurization. Due to the higher investments and energy costs of cases with higher degrees of desulfurization, the annual overall operating costs follow the same trend; the operating costs of cases 2, 4 & 6 are higher than those of cases 1, 3 & 5 respectively.

TABLE 6.2.5.1

ADDITIONAL OPERATING MANPOWER REQUIREMENTS

REGIONS / MANPOWER (PERSONS)	CASE 1	CASE 2	CASE 3	CASE 4	CASE 5	CASE 6
ATLANTIC	0	36	88	170	134	170
QUEBEC	0	18	190	190	190	190
ONTARIO	0	20	124	124	124	124
WESTERN	0	45	441	441	441	441
TOTAL	0	119	843	925	925	925

TABLE 6.2.5.2

INCREASED ANNUAL OPERATING COSTS FOR CATALYSTS/CHEMICALS FOR INDIVIDUAL PROCESS UNITS

ATLANTIC REGION, CASES 1 TO 6

PROCESS UNIT	CATALYSTS AND CHEMICALS IN THOUSANDS OF DOLLARS/YEAR											
	CASE 1		CASE 2		CASE 3		CASE 4		CASE 5		CASE 6	
	CAT	CHEM	CAT	CHEM	CAT	CHEM	CAT	CHEM	CAT	CHEM	CAT	CHEM
HYDROTREATERS												
Naphtha	0	-	0	-	- 8.35	-	- 8.35	-	- 8.53	-	- 8.53	-
Distillate & Gas Oil	39.74	-	132.34	-	- 49.76	-	106.99	-	16.56	-	113.80	-
Kerosene LGO & HO-LO LCO HCO												
H-Oil*	0	-	0	-	9,219.78	-	9,219.78	-	10,085.21	-	10,085.21	-
OTHER UNITS												
Crude a) Caustic	-	0	-	0	-	- 5.41	-	- 5.41	-	- 6.30	-	- 6.30
b) Demulsifier	-	0	-	0	-	- 13.36	-	- 13.36	-	- 15.56	-	- 15.56
Reformer	1.55	-	1.71	-	- 64.17	-	- 65.0	-	- 64.42	-	- 65.14	-
FCCU	0	-	0	-	- 637.18	-	- 637.18	-	53.33	-	53.33	-
Amine	-	- 1.81	-	- 8.18	-	- 12.05	-	- 8.71	-	- 5.87	-	- 2.38
TOTAL	41.29	- 1.81	134.05	- 8.18	8,460.32	- 30.82	8,616.24	- 27.84	10,082.15	- 27.73	10,178.67	- 24.24

TABLE 6.2.5.3

INCREASED ANNUAL OPERATING COSTS FOR CATALYSTS/CHEMICALS FOR INDIVIDUAL PROCESS UNITS

QUEBEC REGION, CASES 1 TO 6

PROCESS UNIT	CATALYSTS AND CHEMICALS IN THOUSANDS OF DOLLARS/YEAR											
	CASE 1		CASE 2		CASE 3		CASE 4		CASE 5		CASE 6	
	CAT	CHEM	CAT	CHEM	CAT	CHEM	CAT	CHEM	CAT	CHEM	CAT	CHEM
HYDROTREATERS												
Naphtha	0	-	0	-	- 44.61	-	- 44.61	-	- 47.88	-	- 47.88	-
Distillate & Gas Oil	100.99	-	279.13	-	- 63.82	-	222.02	-	- 39.20	-	257.69	-
Kerosene LGO & HO-LO												
LCO HCO												
H-Oil*	0	-	0	-	18,304.54	-	18,304.54	-	20,194.08	-	20,194.08	-
OTHER UNITS												
Crude a) Caustic	-	0	-	0	-	- 11.59	-	- 11.59	-		-	- 13.16
b) Demulsifier	-	0	-	0	-	- 28.63	-	- 28.63	-	- 13.16	-	- 32.50
Reformer	- .37	-	1.55	-	- 234.74	-	- 234.94		- 268.34	- 32.50	- 269.32	-
FCCU	0	-	0	-	414.73	-	414.73		797.98		797.98	-
Amine	-	- 3.64	-	- 13.70	-	- 36.63	-	- 31.06	-	- 17.78	-	- 11.95
TOTAL	100.62	- 3.64	280.68	- 13.70	18,376.10	- 76.85	18,661.74	- 71.28	20,636.64	- 63.44	20,932.55	- 57.61

TABLE 6.2.5.4

INCREASED ANNUAL OPERATING COSTS FOR CATALYSTS/CHEMICALS FOR INDIVIDUAL PROCESS UNITS

ONTARIO REGION, CASES 1 TO 6

PROCESS UNIT	CATALYSTS AND CHEMICALS IN THOUSANDS OF DOLLARS/YEAR											
	CASE 1		CASE 2		CASE 3		CASE 4		CASE 5		CASE 6	
	CAT	CHEM	CAT	CHEM	CAT	CHEM	CAT	CHEM	CAT	CHEM	CAT	CHEM
HYDROTREATERS												
Naphtha	0'	-	3.69	-	- 31.12	-	- 31.12	-	- 41.27	-	- 41.27	-
Distillate & Gas Oil	0	-	204.77	-	- 152.47	-	104.63	-	- 51.02	-	211.08	-
Kerosene LGO & HO-LO LCO HCO												
H-Oil*	0	-	0	-	8,467.79	-	8,467.79	-	14,071.30	-	14,071.30	-
OTHER UNITS												
Crude a) Caustic	-	0	-	0	-	- 6.12	-	- 6.12	-	- 8.71	-	- 9.71
b) Demulsifier	-	0	-	0	-	- 15.12	-	- 15.12	-	- 21.51	-	- 21.51
Reformer	0	-	3.89	-	- 152.81	-	- 248.22	-	- 330.35	-	- 327.20	-
FCCU	0	-	0	-	641.40	-	641.40	-	641.40	-	641.40	-
Amine	-	0	-	- 13.66	-	- 14.05	-	- 38.85	-	- 21.14	-	- 35.17
TOTAL	0	0	212.35	- 13.66	8,772.79	- 35.29	8,934.48	- 60.09	14,290.06	- 51.36	14,555.31	- 65.39

TABLE 6.2.5.5

INCREASED ANNUAL OPERATING COSTS FOR CATALYSTS/CHEMICALS FOR INDIVIDUAL PROCESS UNITS

WESTERN REGION, CASES 1 TO 6

PROCESS UNIT	CATALYSTS AND CHEMICALS IN THOUSANDS OF DOLLARS/YEAR											
	CASE 1		CASE 2		CASE 3		CASE 4		CASE 5		CASE 6	
	CAT	CHEM	CAT	CHEM	CAT	CHEM	CAT	CHEM	CAT	CHEM	CAT	CHEM
HYDROTREATERS												
Naphtha	0	-	0	-	- 7.37	-	- 7.37	-	- 18.43	-	- 18.43	-
Distillate & Gas Oil	11.14	-	140.98	-	- 55.81	-	44.77	-	- 49.07	-	71.65	-
Kerosene LGO & HO-LO												
LCO HCO												
H-Oil*	0	-	0	-	8,659.84	-	8,659.84	-	13,429.29	-	13,429.29	-
OTHER UNITS												
Crude a) Caustic	-	0	-	0	-	- 4.21	-	- 4.21	-	- 23.51	-	- 23.51
b) Demulsifier	-	0	-	0	-	- 10.40	-	- 10.40	-	- 11.97	-	- 11.97
Reformer	0.56	-	2.29	-	- 57.83	-	- 54.29	-	- 136.30	-	- 133.58	-
FCCU	0	-	0	-	169.78	-	169.78	-	276.38	-	276.38	-
Amine	-	- .83	-	- 9.21	-	- 11.02	-	- 18.04	-	- 12.82	-	- 9.80
TOTAL	11.70	- .83	143.27	- 9.21	8,708.61	- 25.63	8,812.73	- 32.65	13,501.87	- 48.30	13,625.31	- 45.28

TABLE 6.2.5.6

INCREASED ANNUAL OPERATING COST FOR FEED, PRODUCTS, UTILITIES, CATALYSTS AND CHEMICALS

ATLANTIC REGION

	CASE 1	CASE 2	CASE 3	CASE 4	CASE 5	CASE 6
INCREASED FEEDS :						
A. CRUDE FEED						
i. 34.00 $/bbl (1981)	0.00	0.00	-554.08	-554.08	-644.96	-644.96
ii. 30.00 $/bbl	0.00	0.00	-488.90	-488.90	-569.08	-569.08
iii. 35.00 $/bbl	0.00	0.00	-570.38	-570.38	-663.93	-663.93
iv. 40.00 $/bbl	0.00	0.00	-651.86	-651.86	-758.78	-758.78
B. NAPHTHA	0.00	0.00	9.06	17.08	16.02	24.45
C. NATURAL GAS	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL INCREASED FEED COST						
i. 34.00 $/bbl (1981)	0.00	0.00	-545.02	-537.00	-628.94	-620.51
ii. 30.00 $/bbl	0.00	0.00	-479.84	-471.82	-553.06	-544.63
iii. 35.00 $/bbl	0.00	0.00	-561.32	-553.30	-647.91	-639.48
iv. 40.00 $/bbl	0.00	0.00	-642.80	-634.78	-742.75	-734.33
INCREASED PRODUCTS :						
A. Heavy Fuel Oil ,BPCD	(0)	(0)	(-42533)	(-42533)	(-48076)	(-48076)
Equivalent Coal STPD	(0)	(0)	(-10718)	(-10718)	(-12115)	(-12115)
Equivalent NG MMSCFD	(0)	(0)	(-268)	(-268)	(-303)	(-303)
B. Resid / Pitch ,BPCD	(0)	(0)	(0)	(0)	(-2948)	(-2948)
C. Fuel Gas	-0.70	-3.16	12.69	18.55	30.78	36.95
D. Naphtha	-0.06	2.31	-2.50	1.85	-2.54	2.06
E. Sulfur	0.26	1.04	4.00	3.81	3.37	4.01
TOTAL INCREASED PRODUCT COST(excl. A & B)	-0.51	0.19	14.19	24.20	31.61	43.01
INCREASED UTILITIES :						
A. Fuel	1.32	5.81	-0.56	13.03	2.81	17.09
B. Electricity	0.18	0.74	4.12	5.45	5.76	7.16
C. Steam	0.12	0.58	-6.87	-6.34	-6.24	-5.72
D. Cooling Water	0.04	0.18	0.16	0.65	0.33	0.85
TOTAL INCREASED UTILITIES COST	1.65	7.31	-3.15	12.80	2.67	19.37
INCREASED CATALYSTS AND CHEMICALS						
A. Catalysts	0.04	0.13	8.46	8.62	10.08	10.18
B. Chemicals	-0.00	-0.01	-0.03	-0.03	-0.03	-0.02
TOTAL INCREASED CAT & CHEM'S COST	0.04	0.13	8.43	8.59	10.05	10.15

Notes : "-" denotes decrease.
All costs are Million $/year.
All costs are based on 1982, except crude cost, which is based on 1981.
FOEB = 6.3 MMBTU , Coal = 12500 BTU/lb , NG = 1000 BTU/SCF
Figures in brackets are flow rates.

TABLE 6.2.5.7

INCREASED ANNUAL OPERATING COST FOR FEED, PRODUCTS, UTILITIES, CATALYSTS AND CHEMICALS

QUEBEC REGION

	CASE 1	CASE 2	CASE 3	CASE 4	CASE 5	CASE 6
INCREASED FEEDS :						
A. CRUDE FEED						
i. 34.00 $/bbl (1981)	0.00	0.00	-1186.86	-1186.86	-1347.53	-1347.53
ii. 30.00 $/bbl	0.00	0.00	-1047.23	-1047.23	-1188.99	-1188.99
iii. 35.00 $/bbl	0.00	0.00	-1221.76	-1221.76	-1387.16	-1387.16
iv. 40.00 $/bbl	0.00	0.00	-1396.30	-1396.30	-1585.33	-1585.33
B. NAPHTHA	0.00	0.00	0.00	0.00	0.00	0.00
C. NATURAL GAS	0.00	0.00	2.39	16.23	16.74	30.92
TOTAL INCREASED FEED COST						
i. 34.00 $/bbl (1981)	0.00	0.00	-1184.46	-1170.63	-1330.79	-1316.61
ii. 30.00 $/bbl	0.00	0.00	-1044.83	-1031.00	-1172.25	-1158.08
iii. 35.00 $/bbl	0.00	0.00	-1219.37	-1205.53	-1370.42	-1356.24
iv. 40.00 $/bbl	0.00	0.00	-1393.91	-1380.07	-1568.59	-1554.41
INCREASED PRODUCTS :						
A. Heavy Fuel Oil ,BPCD	(0)	(0)	(-91410)	(-91410)	(-93681)	(-93681)
Equivalent Coal STPD	(0)	(0)	(-23035)	(-23035)	(-23608)	(-23608)
Equivalent NG MMSCFD	(0)	(0)	(-576)	(-576)	(-590)	(-590)
B. Resid / Pitch ,BPCD	(0)	(0)	(0)	(0)	(-13954)	(-13954)
C. Fuel Gas	-0.82	-4.70	21.67	30.25	61.07	70.04
D. Naphtha	1.13	4.17	-3.89	3.32	-3.44	4.33
E. Sulfur	0.23	1.32	7.40	8.50	7.79	8.92
TOTAL INCREASED PRODUCT COST(excl. A & B)	0.55	0.79	25.17	42.06	65.42	83.29
INCREASED UTILITIES :						
A. Fuel	2.76	7.91	-12.43	7.90	-0.64	20.32
B. Electricity	0.23	0.62	4.49	5.81	6.72	8.09
C. Steam	0.87	1.12	-15.69	-15.00	-15.01	-14.21
D. Cooling Water	0.12	0.31	-0.00	0.85	0.72	1.59
TOTAL INCREASED UTILITIES COST	3.98	9.96	-23.63	-0.45	-8.20	15.79
INCREASED CATALYSTS AND CHEMICALS						
A. Catalysts	0.10	0.28	18.38	18.66	20.64	20.93
B. Chemicals	-0.00	-0.01	-0.08	-0.07	-0.06	-0.06
TOTAL INCREASED CAT & CHEM'S COST	0.10	0.27	18.30	18.59	20.57	20.87

Notes : "-" denotes decrease.
All costs are Million $/year.
All costs are based on 1982, except crude cost, which is based on 1981.
FOEB = 6.3 MMBTU , Coal = 12500 BTU/lb , NG = 1000 BTU/SCF
Figures in brackets are flow rates.

TABLE 6.2.5.8

INCREASED ANNUAL OPERATING COST FOR FEED, PRODUCTS, UTILITIES, CATALYSTS AND CHEMICALS

ONTARIO REGION

	CASE 1	CASE 2	CASE 3	CASE 4	CASE 5	CASE 6
INCREASED FEEDS :						
A. CRUDE FEED						
i. 34.00 $/bbl (1981)	0.00	0.00	-627.10	-627.10	-891.68	-891.68
ii. 30.00 $/bbl	0.00	0.00	-551.33	-551.33	-786.78	-786.78
iii. 35.00 $/bbl	0.00	0.00	-645.55	-645.55	-917.91	-917.91
iv. 40.00 $/bbl	0.00	0.00	-737.77	-737.77	-1049.04	-1049.04
B. NAPHTHA	0.00	0.00	0.00	0.00	0.00	0.00
C. NATURAL GAS	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL INCREASED FEED COST						
i. 34.00 $/bbl (1981)	0.00	0.00	-627.10	-627.10	-891.68	-891.68
ii. 30.00 $/bbl	0.00	0.00	-551.33	-551.33	-786.78	-786.78
iii. 35.00 $/bbl	0.00	0.00	-645.55	-645.55	-917.91	-917.91
iv. 40.00 $/bbl	0.00	0.00	-737.77	-737.77	-1049.04	-1049.04
INCREASED PRODUCTS :						
A. Heavy Fuel Oil ,BPCD	(0)	(0)	(-50704)	(-50704)	(-63712)	(-63712)
Equivalent Coal STPD	(0)	(0)	(-12777)	(-12777)	(-16055)	(-16055)
Equivalent NG MMSCFD	(0)	(0)	(-319)	(-319)	(-401)	(-401)
B. Resid / Pitch ,BPCD	(0)	(0)	(0)	(0)	(-7296)	(-7296)
C. Fuel Gas	0.00	-4.40	25.07	14.32	22.33	18.01
D. Naphtha	0.00	3.09	-0.40	2.67	-0.22	4.62
E. Sulfur	0.00	0.91	3.94	4.86	4.63	5.56
TOTAL INCREASED PRODUCT COST(excl. A & B)	0.00	0.40	28.61	21.84	26.74	28.19
INCREASED UTILITIES :						
A. Fuel	0.00	5.15	-6.43	-1.69	-8.10	-2.52
B. Electricity	0.00	0.58	4.13	4.29	4.92	5.57
C. Steam	0.00	-0.15	-9.25	-9.53	-9.06	-9.20
D. Cooling Water	0.00	0.20	0.09	0.27	0.04	0.26
TOTAL INCREASED UTILITIES COST	0.00	5.79	-11.46	-6.65	-12.20	-5.89
INCREASED CATALYSTS AND CHEMICALS						
A. Catalysts	0.00	0.21	8.77	8.93	14.29	14.56
B. Chemicals	0.00	-0.01	-0.04	-0.06	-0.05	-0.07
TOTAL INCREASED CAT & CHEM'S COST	0.00	0.20	8.74	8.87	14.24	14.49

Notes : "-" denotes decrease.
All costs are Million $/year.
All costs are based on 1982, except crude cost, which is based on 1981.
FOEB = 6.3 MMBTU , Coal = 12500 BTU/lb , NG = 1000 BTU/SCF
Figures in brackets are flow rates.

TABLE 6.2.5.9

INCREASED ANNUAL OPERATING COST FOR FEED, PRODUCTS, UTILITIES, CATALYSTS AND CHEMICALS

WESTERN REGION

	CASE 1	CASE 2	CASE 3	CASE 4	CASE 5	CASE 6
INCREASED FEEDS :						
A. CRUDE FEED						
i. 34.00 $/bbl (1981)	0.00	0.00	-431.10	-431.10	-499.40	-499.40
ii. 30.00 $/bbl	0.00	0.00	-380.38	-380.38	-440.65	-440.65
iii. 35.00 $/bbl	0.00	0.00	-443.78	-443.78	-514.09	-514.09
iv. 40.00 $/bbl	0.00	0.00	-507.17	-507.17	-587.53	-587.53
B. NAPHTHA	0.00	0.00	0.00	0.00	0.00	0.00
C. NATURAL GAS	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL INCREASED FEED COST						
i. 34.00 $/bbl (1981)	0.00	0.00	-431.10	-431.10	-499.40	-499.40
ii. 30.00 $/bbl	0.00	0.00	-380.38	-380.38	-440.65	-440.65
iii. 35.00 $/bbl	0.00	0.00	-443.78	-443.78	-514.09	-514.09
iv. 40.00 $/bbl	0.00	0.00	-507.17	-507.17	-587.53	-587.53
INCREASED PRODUCTS :						
A. Heavy Fuel Oil ,BPCD	(0)	(0)	(-24807)	(-24807)	(-16157)	(-16157)
Equivalent Coal STPD	(0)	(0)	(-6251)	(-6251)	(-4072)	(-4072)
Equivalent NG MMSCFD	(0)	(0)	(-156)	(-156)	(-102)	(-102)
B. Resid / Pitch ,BPCD	(0)	(0)	(-7568)	(-7568)	(-22270)	(-22270)
C. Fuel Gas	-0.24	-2.16	12.28	10.40	18.75	21.01
D. Naphtha	0.02	2.96	0.65	1.57	0.64	2.59
E. Sulfur	0.07	0.60	3.07	3.58	3.35	3.86
TOTAL INCREASED PRODUCT COST(excl. A & B)	-0.16	1.40	16.00	15.55	22.74	27.45
INCREASED UTILITIES :						
A. Fuel	0.19	2.70	-1.01	0.79	-2.06	0.09
B. Electricity	0.02	0.31	3.33	3.52	3.83	4.31
C. Steam	-0.02	-0.09	-6.69	-6.79	-6.32	-6.33
D. Cooling Water	0.01	0.14	0.14	0.23	0.07	0.19
TOTAL INCREASED UTILITIES COST	0.20	3.07	-4.23	-2.25	-4.47	-1.75
INCREASED CATALYSTS AND CHEMICALS						
A. Catalysts	0.01	0.14	8.71	8.81	13.50	13.63
B. Chemicals	-0.00	-0.01	-0.03	-0.03	-0.05	-0.05
TOTAL INCREASED CAT & CHEM'S COST	0.01	0.13	8.68	8.78	13.45	13.58

Notes : "-" denotes decrease.
All costs are Million $/year.
All costs are based on 1982, except crude cost, which is based on 1981.
FOEB = 6.3 MMBTU , Coal = 12500 BTU/lb , NG = 1000 BTU/SCF
Figures in brackets are flow rates.

TABLE 6.2.5.10

CAPITAL INVESTMENT AND INCREASED ANNUAL OPERATING COSTS

ATLANTIC REGION

CASE	1	2	3	4	5	6
CRUDE RATE, BPCD	220,692	220,692	176,044	176,044	168,721	168,721
I. CAPITAL INVESTMENT, MM$	0	42.59	307.88	341.19	343.42	376.54
II. INCREASED ANNUAL OPERATING COSTS, MM$/YR.						
1. Annual Capital Charge	0	10.65	76.97	85.30	85.86	94.14
2. Fixed Costs						
(i) Operating Personnel	0	1.35	3.30	6.37	5.02	6.37
(ii) Maintenance	0	1.28	9.24	10.24	10.30	11.30
(iii) General, Sales, Administration	0	1.49	10.76	11.94	12.02	13.18
3. Decreased Feed Credit						
(i) Crude @ 34.0 $/B	0	0	- 545.02	- 537.00	- 628.94	- 620.51
(ii) " " 30.0 $/B	0	0	- 479.84	- 471.82	- 552.06	- 544.63
(iii) " " 35.0 $/B	0	0	- 561.32	- 553.30	- 647.91	- 639.48
(iv) " " 40.0 $/B	0	0	- 642.80	- 634.78	- 742.75	- 734.33
4. Increased Product Credit*	0.51	- 0.19	- 14.19	- 24.20	- 31.61	- 43.01
(Decreased HFO, 10^3B/YR.)	(0)	(0)	(15,525)	(15,525)	(17,548)	(17,548)
(Decreased Resid/Pitch, 10^3B/YR.)	(0)	(0)	(0)	(0)	(1,706)	(1,706)
5. Increased Energy/Utility Cost	1.65	7.31	- 3.15	12.80	2.67	19.37
6. Increased Cat. & Chem. Cost	0.04	0.13	8.43	8.59	10.05	10.15
III. Total of II; MM$/YR.						
1. Total of 1+2+3(i)+4+5+6	2.20	22.02	- 453.66	- 425.96	- 534.63	- 509.01
2. Total of 1+2+3(ii)+4+5+6	2.20	22.02	- 388.48	- 360.78	- 458.75	- 433.13
3. Total of 1+2+3(iii)+4+5+6	2.20	22.02	- 469.96	- 442.26	- 553.60	- 527.98
4. Total of 1+2+3(iv)+4+5+6	2.20	22.02	- 551.44	- 523.74	- 648.44	- 622.83

NOTES:
1. All costs are in millions of dollars per year.
2. "-" denotes credit.

* Excluding HFO & Resid/Pitch.

TABLE 6.2.5.11

CAPITAL INVESTMENT AND INCREASED ANNUAL OPERATING COSTS

QUEBEC REGION

CASE	1	2	3	4	5	6
CRUDE RATE, BPCD	484,623	484,623	388,986	388,986	376,039	376,039
I. CAPITAL INVESTMENT, MM$	0	3.31	569.79	594.15	640.59	692.93
II. INCREASED ANNUAL OPERATING COSTS, MM$/YR.						
1. Annual Capital Charge	0	0.83	142.45	148.54	160.15	173.23
2. Fixed Costs						
(i) Operating Personnel	0	0.68	7.12	7.12	7.12	7.12
(ii) Maintenance	0	0.10	17.09	17.82	19.22	20.79
(iii) General, Sales, Administration	0	0.12	19.94	20.80	22.42	24.25
3. Decreased Feed Credit						
(i) Crude @ 34.0 $/B	0	0	-1,184.46	-1,170.63	-1,330.79	-1,316.61
(ii) " " 30.0 $/B	0	0	-1,044.83	-1,031.00	-1,172.25	-1,158.08
(iii) " " 35.0 $/B	0	0	-1,219.37	-1,205.53	-1,370.42	-1,356.24
(iv) " " 40.0 $/B	0	0	-1,393.91	-1,380.07	-1,568.59	-1,554.41
4. Increased Product Credit*	- 0.55	- 0.79	- 25.17	- 42.06	- 65.42	- 83.29
(Decreased HFO, 10^3B/YR.)	(0)	(0)	(33,365)	(33,365)	(34,194)	(34,194)
(Decreased Resid/Pitch, 10^3B/YR.)	(0)	(0)	(0)	(0)	(5,093)	(5,093)
5. Increased Energy/Utility Cost	3.98	9.96	- 23.63	- 0.45	- 8.20	15.79
6. Increased Cat. & Chem. Cost	0.10	0.27	18.30	18.59	20.57	20.87
III. Total of II; MM$/YR.						
1. Total of 1+2+3(i)+4+5+6	3.53	11.17	-1,028.36	-1,000.27	-1,174.93	-1,137.85
2. Total of 1+2+3(ii)+4+5+6	3.53	11.17	- 888.73	- 860.64	-1,016.39	- 979.32
3. Total of 1+2+3(iii)+4+5+6	3.53	11.17	-1,063.27	-1,035.17	-1,214.56	-1,177.48
4. Total of 1+2+3(iv)+4+5+6	3.53	11.17	-1,237.81	-1,209.71	-1,412.73	-1,375.65

NOTES:
1. All costs are in millions of dollars per year.
2. "-" denotes credit.

* Excluding HFO & Resid/Pitch.

TABLE 6.2.5.12

CAPITAL INVESTMENT AND INCREASED ANNUAL OPERATING COSTS

ONTARIO REGION

CASE	1	2	3	4	5	6
CRUDE RATE, BPCD	565,954	565,954	515,422	515,422	494,102	494,102
I. CAPITAL INVESTMENT, MM$	0	2.07	372.00	373.71	415.37	417.31
II. INCREASED ANNUAL OPERATING COSTS, MM$/YR.						
1. Annual Capital Charge	0	0.52	93.00	93.43	103.84	104.33
2. Fixed Costs						
(i) Operating Personnel	0	0.75	4.65	4.65	4.65	4.65
(ii) Maintenance	0	0.06	11.16	11.21	12.46	12.52
(iii) General, Sales, Administration	0	0.07	13.02	13.08	14.54	14.61
3. Decreased Feed Credit						
(i) Crude @ 34.0 $/B	0	0	- 627.10	- 627.10	- 891.68	- 891.68
(ii) " " 30.0 $/B	0	0	- 553.33	- 553.33	- 786.78	- 786.78
(iii) " " 35.0 $/B	0	0	- 645.55	- 645.55	- 917.91	- 917.91
(iv) " " 40.0 $/B	0	0	- 737.77	- 737.77	-1,049.04	-1,049.04
4. Increased Product Credit*	0	- 0.40	- 28.61	- 21.84	- 26.74	- 28.19
(Decreased HFO, 10^3B/YR.)	(0)	(0)	(18,507)	(18.507)	(23,255)	(23,255)
(Decreased Resid/Pitch, 10^3B/YR.)	(0)	(0)	(0)	(0)	(2,663)	(2,663)
5. Increased Energy/Utility Cost	0	5.79	- 11.46	- 6.65	- 12.20	- 5.89
6. Increased Cat. & Chem. Cost	0	0.20	8.74	8.87	14.24	14.49
III. Total of II; MM$/YR.						
1. Total of 1+2+3(i)+4+5+6	0	6.99	- 536.60	- 524.35	- 780.89	- 775.16
2. Total of 1+2+3(ii)+4+5+6	0	6.99	- 462.83	- 450.58	- 675.99	- 670.26
3. Total of 1+2+3(iii)+4+5+6	0	6.99	- 555.05	- 542.80	- 807.12	- 801.39
4. Total of 1+2+3(iv)+4+5+6	0	6.99	- 647.27	- 635.02	- 538.25	- 932.52

NOTES:
1. All costs are in millions of dollars per year.
2. "-" denotes credit.

* Excluding HFO & resid/Pitch.

TABLE 6.2.5.13

CAPITAL INVESTMENT AND INCREASED ANNUAL OPERATING COSTS

WESTERN REGION

CASE	1	2	3	4	5	6
CRUDE RATE, BPCD	534,463	534,463	499,725	499,725	494,221	494,221
I. CAPITAL INVESTMENT, MM$	0	4.43	469.56	472.76	480.90	484.09
II. INCREASED ANNUAL OPERATING COSTS, MM$/YR.						
1. Annual Capital Charge	0	1.11	117.39	118.19	120.23	121.02
2. Fixed Costs						
(i) Operating Personnel	0	1.69	16.52	16.52	16.52	16.52
(ii) Maintenance	0	0.13	14.09	14.18	14.43	14.52
(iii) General, Sales, Administration	0	0.16	16.43	16.55	15.83	16.94
3. Decreased Feed Credit						
(i) Crude @ 34.0 $/B	0	0	- 431.10	- 431.10	- 499.40	- 499.40
(ii) " " 30.0 $/B	0	0	- 380.38	- 380.38	- 440.65	- 440.65
(iii) " " 35.0 $/B	0	0	- 443.78	- 443.78	- 514.09	- 514.09
(iv) " " 40.0 $/B	0	0	- 507.17	- 507.17	- 587.53	- 587.53
4. Increased Product Credit *	0.16	- 1.40	- 16.00	- 15.55	- 22.74	- 27.45
(Decreased HFO, 10^3B/YR.)	(0)	(0)	(9,055)	(9,055)	(5,897)	(5,897)
(Decreased Resid/Pitch, 10^3B/YR.)	(0)	(0)	(2,762)	(2,762)	(8,129)	(8,129)
5. Increased Energy/Utility Cost	0.20	3.07	- 4.23	- 2.25	- 4.47	- 1.75
6. Increased Cat. & Chem. Cost	0.01	0.13	8.68	8.78	13.45	13.58
III. Total of II; MM$/YR.						
1. Total of 1+2+3(i)+4+5+6	0.37	4.89	- 278.22	- 274.68	- 345.15	- 346.02
2. Total of 1+2+3(ii)+4+5+6	0.37	4.89	- 227.50	- 223.96	- 286.40	- 287.27
3. Total of 1+2+3(iii)+4+5+6	0.37	4.89	- 290.90	- 287.36	- 359.84	- 360.71
4. Total of 1+2+3(iv)+4+5+6	0.37	4.89	- 354.29	- 350.75	- 433.28	- 434.15

NOTES: 1. All costs are in millions of dollars per year.

2. "-" denoted credit.

* Excluding HFO & Resid/Pitch.

6.2.6 Capital Investments for New Facilities

The capital investments for the required additional process and ancillary unit capacities were estimated based on the procedures described in Chapter 5. The capital investments required for all cases in the four regions are summarized in Tables 6.2.6.1 to 4. Back-up calculations for individual refineries are included in Appendices III and IV.

If H-Oil units are not used, no investments are required to achieve 0.3 wt% sulfur in LFO and lighter products for all regions (Cases 1). To achieve 0.1 wt% sulfur in LFO and lighter products (Cases 2), investment is required in the Atlantic region for kerosene hydrotreating facilities. In Cases 3 to 6 where H-Oil units were added, major portions of the capital investments required are for H-Oil units. In Atlantic and Quebec regions, significant portions of the capital investments go to hydrogen plants. Higher investments are required to achieve higher degrees of desulfurization (0.1 wt% sulfur versus 0.3 wt% sulfur) in LFO and lighter products.

The H-Oil units in many refineries in the Western region are on the lower end of the capital investment curve which gives higher capital per unit throughput. As a result the capital investment required to achieve a certain crude oil reduction is relatively high in the Western region.

TABLE 6.2.6.1

CAPITAL INVESTMENT REQUIRED FOR ADDITIONAL CAPACITIES

ATLANTIC REGION

COST $MM / CASE	KERO HTU	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER	RELATED OFFSITES COST	TOTAL
		90%	66%						
CASE 1	-	-	-	-	-	-	-	-	
CASE 2	38.72	-	-	-	-	-	-	3.87	42.59
CASE 3	-	-	218.23	59.40	-	-	2.26	27.99	307.88
CASE 4	28.39	-	218.23	82.13	-	6.21	3.60	31.02	341.19
CASE 5	-	238.24	-	67.16	-	4.66	2.14	31.22	343.42
CASE 6	26.84	238.24	-	94.01	-	6.54	3.52	34.23	376.54

TABLE 6.2.6.2

CAPITAL INVESTMENT REQUIRED FOR ADDITIONAL CAPACITIES

QUEBEC REGION

COST $MM / CASE	KERO HTU	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER	RELATED OFFSITES COST	TOTAL
		90%	66%						
CASE 1	-	-	-	-	-	-	-	-	
CASE 2	-	-	-	-	-	-	1.88	0.19	2.07
CASE 3	-	-	332.06	-	-	-	6.12	33.82	372.00
CASE 4	-	-	332.06	-	-	-	7.68	33.97	373.71
CASE 5	-	371.16	-	-	-	-	6.45	37.76	415.37
CASE 6	-	371.16	-	-	-	-	8.21	37.94	417.31

TABLE 6.2.6.3

CAPITAL INVESTMENT REQUIRED FOR ADDITIONAL CAPACITIES

ONTARIO REGION

CASE \ COST $MM	KERO HTU	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER	RELATED OFFSITES COST	TOTAL
		90%	66%						
CASE 1	-	-	-	-	-	-	-	-	
CASE 2	-	-	-	-	-	-	3.01	0.3	3.31
CASE 3	-	-	408.24	85.05	-	17.22	7.48	51.80	569.79
CASE 4	-	-	408.24	102.40	-	19.86	9.64	54.01	594.15
CASE 5	-	454.31	-	102.40	-	18.11	7.53	58.24	640.59
CASE 6	-	454.31	-	145.27	-	20.62	9.74	62.99	692.93

TABLE 6.2.6.4

CAPITAL INVESTMENT REQUIRED FOR ADDITIONAL CAPACITIES

WESTERN REGION

COST $MM / CASE	KERO HTU	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER	RELATED OFFSITES COST	TOTAL
		90%	66%						
CASE 1	-	-	-	-	-	-	-	-	
CASE 2	-	-	-	-	-	-	4.03	0.40	4.43
CASE 3	-	-	393.81	-	-	24.51	8.55	42.69	469.56
CASE 4	-	-	393.81	-	-	26.50	9.47	42.98	472.76
CASE 5	-	403.44	-	-	-	25.58	8.16	43.72	480.90
CASE 6	-	403.44	-	-	-	27.34	9.30	44.01	484.09

7.0 OVERALL ASSESSMENT

This chapter presents the summaries of:

Annual Sulfur Reductions (Table 7.1),

Changes in Annual Crude Oil Requirements and Petroleum Products (Table 7.2.),

Additional Capacities Required for Process and Ancillary Units (Table 7.3),

Increased Annual Energy/Utility Requirements (Table 7.4),

Increased Annual Operating Costs for Utilities and Materials (Table 7.5),

Capital Investments (Table 7.6), and

Capital Investment and Increased Annual Operating Costs (Tables 7.7.1 to 6).

These tables were developed from the results of individual regions presented in Chapter 6. The results for Canada as a whole were derived from the sum of the four regions.

(a) Case 1

To achieve the objective of 0.3 wt% sulfur in HFO and lighter products while maintaining the sulfur content in HFO at same level as the reference base case, no additional investment is required in Canada. There is a sulfur reduction of 6,165 tonnes (metric)/year. The existing hydrotreating facilities have sufficient capacities to achieve this objective on the basis of composite refineries and assuming the facilities have flexibility in treating multiple feedstocks. The increase in annual operating cost with respect to the reference base case is 6.1 million dollars/year or in the order of 1¢/Bbl crude feed based on Canada as a whole. Increase in operating costs are higher for Atlantic and Quebec regions which crude diets have higher sulfur contents, and low for Western region.

No increase in operating cost is required for Ontario region, since the 1981 operation as simulated in the reference base case is already within the sulfur content limit.

Case 2

For Canada as a whole, an extra investment of 52.4 million dollars is required to achieve the objective of 0.1 wt% sulfur in LFO and lighter products. The sulfur reduction as compared to the simulated 1981 operation is 43,766 tonnes/year. Most of this investment is required for hydrotreating facility in Atlantic region. The increase in annual operating cost with respect to the reference base case is about 45 million dollars/year or 7¢/Bbl crude feed for Canada as a whole. Increase in operating costs are higher for Atlantic and Quebec regions again because of their higher sulfur crude diets.

(b) Case 3

To achieve the objective of 0.3 wt% sulfur in LFO and lighter products and at the same time minimizing the HFO production by means of hydrocracking the vacuum resid using 66 LV% conversion H-Oil process, extra investment required for Canada as a whole is 1.72 billion dollars, mostly for the H-Oil units and hydrogen plants (only required for Atlantic and Quebec regions). Distribution of the extra investment among the four regions greatly depends on the vacuum resid ($975^{o}F^{+}$) available. Therefore, Atlantic and Quebec regions have a higher incremental investment per unit crude feed.

With this investment, the crude oil requirement for Canada is reduced by 82.3 million barrels per year (12.5%) along with equivalent reduction in HFO and resid productions. The total sulfur reduction in fuel oil products is 268,626 tonnes/year. The extra sulfur reduction as compared to cases without the

H-Oil units come from the reduction in HFO production.

Case 4

To achieve 0.1 wt% sulfur in LFO and lighter products and maintain the same objective as before of reducing crude requirement using 66 LV% conversion H-Oil process, the extra investment required for Canada is 1.78 billion dollars, again mostly for the H-Oil units and hydrogen plants. Distribution of the extra investment among the regions and the requirements of crude oil are similar to the previous case (Case 3). With this investment, the sulfur reduction in fuel oil products is 306,267 tonnes/year. The extra sulfur reduction as compared to cases without the H-Oil units again is due to the reduction in HFO production.

(c) Case 5

To achieve 0.3 wt% sulfur in LFO and lighter products and at the same time minimizing the HFO production by adding the 90 LV% conversion H-Oil process to crack the vacuum resid, extra investment required for Canada is 1.88 billion dollars. With the higher investment, a higher reduction in crude requirement of 99.5 million barrels per year (and equivalent mangnitude of reduction in HFO and resid production) for Canada can be achieved. The total sulfur reduction in fuel oil production is 282,802 tonnes/year mainly due to reduction in HFO production.

Case 6

To achieve 0.1 wt% sulfur in HFO and lighter products and maintain the same objective as the previous case of reducing crude requirement by adding 90 LV% conversion H-Oil units, the extra investment required for Canada is 1.97 billion dollars mostly for the H-Oil units. The reduction in crude requirement is the same as the previous case (Case 5). The sulfur reduction in fuel oil products is 320,589 tonnes/year. The extra sulfur reduction as compared to the previous case is due to higher degrees of desulfurization of the products.

(d) Based on the figures presented above, the extra investment required for the reduction of crude oil requirement and equivalent HFO and resid production is in the order of $16 - 18 per barrel (higher for Western region). If alternative fuels with no sulfur or with low sulfur emission during combustion are available to substitute the market demand of HFO, substantial reduction in sulfur emission due to combustion of HFO can be achieved at the same time as crude oil reduction. The economics would, to a certain extent, depend upon the price difference between crude oil and the substituting fuels. It is likely that only part of the HFO market can be practically substituted. The simulation carried out in this study represents the maximum reduction in HFO production using a particular process based on 1981 operation.

To illustrate the economics of hydrocracking the vacuum resid to reduce crude oil requirement and sulfur in the fuel oil products, the increased annual operating costs per barrel of crude were calculated based on annual capital charge of 25%, crude prices at several levels, HFO at $34/Bbl and resid at $23/Bbl. Based on the results which are included in Appendix A II, the increased annual operating are higher for regions which have higher $975^{0}F^{+}$ material per barrel of crude. The economics depends on the price difference between crude oil and HFO, and became feasible when the HFO price is around 4 or 5 dollars below the crude price. H-Oil process was used as a basis of this study to explore the potential of the resid conversion technology in achieving the sulfur reduction objective. The illustration presented here should be interpreted as an indication of how the different prices affected the economics. If other process is used as a basis, the economics will change accordingly.

TABLE 7.1

SUMMARY OF ANNUAL REDUCTION OF SULFUR

CASE		REGION	REFINERY'S OWN FUEL CONSUMPTION TONNE	SALEABLE PRODUCTS		TOTAL TONNE
				HEAVY FUEL OILS #4, #5, #6 TONNE	LIGHT FUEL OILS (LFO, DIESEL, KERO/STOVE) TONNE	
1	#2 FUEL	A	10	28	2 990	3 028
	OIL AND	Q	17	107	2 192	2 316
	LIGHTER	O	0	0	0	0
	0.3 WT.%	W	2	57	762	821
	S. MAX.	CANADA	29	192	5 944	6 165
2	#2 FUEL	A	35	55	10 154	10 244
	OIL AND	Q	66	107	14 895	15 068
	LIGHTER	O	40	0	11 432	11 472
	0.1 WT. %	W	16	171	6 795	6 982
	S. MAX.	CANADA	157	333	45 276	43 766
3	#2 FUEL OIL	A	835	66 751 (1)	2 850	70 436
	AND LIGHTER	Q	348	119 238 (1)	1 961	121 547
	0.3 WT.% S +	O	2 499	51 920 (1)	17	54 436
	H-OIL LOW	W	91	21 296 (1)	820	22 207
	CONVERSION	CANADA	3 773	259 205	5 648	268 626
4	#2 FUEL OIL	A	859	66 755 (1)	10 108	77 722
	AND LIGHTER	Q	398	119 238 (1)	14 827	134 463
	0.1 WT. % S +	O	2 547	51 933 (1)	11 436	65 916
	H-OIL LOW	W	100	21 296 (1)	6 770	28 166
	CONVERSION	CANADA	3 904	259 222	43 141	306 267
5	#2 FUEL OIL	A	3 034	73 864 (1)	2 818	79 716
	AND LIGHTER	Q	- 620	122 133 (1)	1 826	123 339
	0.3 WT.% S +	O	2 085	61 707 (1)	- 146	63 646
	H-OIL HIGH	W	132	15 160 (1)	809	16 101
	CONVERSION	CANADA	4 631	272 864	5 307	282 802
6	#2 FUEL OIL	A	3 058	73 864 (1)	10 092	87 014
	AND LIGHTER	Q	- 564	122 133 (1)	14 718	136 287
	0.1 WT.% S +	O	2 133	61 713 (1)	11 378	75 224
	H-OIL HIGH	W	141	15 160 (1)	6 763	22 064
	CONVERSION	CANADA	4 768	272 870	42 951	320 589

NOTES: (1) Increased Sulfur reduction due to less "Saleable HFO" available.

"-" denotes an increase.

TABLE 7.2

SUMMARY OF CHANGES IN ANNUAL CRUDE OIL REQUIREMENT AND PETROLEUM PRODUCTS

CASE	REGION	FEED			PETROLEUM PRODUCTS					
		CRUDE	TO H_2 PLT.		HFO	RESID/PITCH TO ASPHALT	H_2 TO HTU'S & H-OIL	REFINERY FUEL GAS	NAPHTHA FROM HTU'S	SULFUR
			NAPH.*	N.G.						
		10^3 Bbl	10^3 Bbl	10^6 SCF	10^3 Bbl	10^3 Bbl	10^6 SCF	10^9 BTU	10^3 Bbl	10^3 ST
1	A	0	0	0	0	0	1,643	- 130	- 1	3
	Q	0	0	0	0	0	2,920	- 174	27	3
	O	0	0	0	0	0	0	0	0	0
	W	0	0	0	0	0	511	- 82	0	1
	CANADA	0	0	0	0	0	5,074	- 386	26	7
2	A	0	0	0	0	0	6,169	- 586	54	14
	Q	0	0	0	0	0	9,673	-1,004	98	17
	O	0	0	0	0	0	3,614	-1,112	92	12
	W	0	0	0	0	0	5,950	- 727	70	8
	CANADA	0	0	0	0	0	14,564	-3,429	314	51
3	A	-16,297	213	0	-15,525	0	11,023	2,351	- 59	42
	Q	-34,908	0	511	-33,365	0	28,908	4,629	- 92	97
	O	-18,444	0	0	-18,507	0	12,885	6,332	- 9	52
	W	-12,679	0	0	-9,055	-2,762	13,870	4,135	15	40
	CANADA	-82,328	213	511	-76,452	-2,762	66,686	17,447	-145	231
4	A	-16,297	402	0	-15,525	0	10,987	3,436	43	50
	Q	-34,908	0	3,468	-33,365	0	28,908	6,463	78	112
	O	-18,444	0	0	-18,507	0	27,083	3,615	63	64
	W	-12,679	0	0	- 9,055	-2,762	18,323	3,503	37	47
	CANADA	-82,328	402	3,468	-76,452	-2,762	85,301	17,017	221	273
5	A	-18,969	377	0	-17,548	-1,076	11,607	5,703	- 60	44
	Q	-39,633	0	3,577	-34,194	- 509	27,448	13,049	- 81	103
	O	-26,226	0	0	-23,255	-2,663	19,163	5,638	- 5	61
	W	-14,688	0	0	-5,897	-8,129	17,593	6,313	15	44
	CANADA	-99,516	377	3,577	-80,894	-12,377	75,811	30,703	-131	252
6	A	-18,969	575	0	-17,548	-1,076	11,607	6,846	49	53
	Q	-39,633	0	6,607	-34,194	- 509	27,448	14,966	102	117
	O	-26,226	0	0	-23,255	-2,663	28,324	4,549	109	73
	W	-14,688	0		-5,897	-8,129	22,557	7,073	61	51
	CANADA	-99,516	575	6,607	-80,894	-12,377	89,936	33,434	321	294

NOTES: * Net naphtha required.

"-" denotes a decrease in flowrate.

TABLE 7.3

SUMMARY OF ADDITIONAL CAPACITIES REQUIRED FOR PROCESS AND ANCILLARY UNITS

CASE	REGION	CRUDE CAPACITY BPCD	%	KEROSENE HYDROTREATER BPSD	H-OIL UNIT BPSD	H_2 PLANT (97%) MMSCF/SD	SULFUR PLANT ST/SD	SOUR WATER STRIPPER BPSD
1	A	367,300	16.1				0	0
	Q	617,400	27.1				0	0
	O	758,200	33.3				0	0
	W	535,100	23.5				0	0
	CANADA	2,278,600	100.0	0	0	0	0	0
2	A	367,900	16.1	11,770			0	0
	Q	617,400	27.1	0			0	2,229
	O	758,200	33.3	0			0	1,004
	W	535,100	23.5	0			0	1,491
	CANADA	2,278,600	100.0	11,770	0	0	0	4,724
3	A	367,900	16.1		39,980	17.5	0	2,150
	Q	617,400	27.1		79,360	6.0	180	9,624
	O	758,200	33.3		65,495	0	0	6,112
	W	535,100	23.5		67,000	0	82	7,200
	CANADA	2,278,600	100.0	0	251,835	23.5	262	24,086
4	A	367,900	16.1	1,900	39,980	37.0	24	4,441
	Q	617,400	27.1	0	79,360	40.0	255	12,500
	O	758,200	33.3	0	65,495	0	0	8,615
	W	535,100	23.5	0	67,000	0	104	9,495
	CANADA	2,278,600	100.0	1,900	251,835	77.0	383	34,251
5	A	367,900	16.1		38,300	29.0	9	1,932
	Q	617,400	27.1		76,750	40.0	197	8,694
	O	758,200	33.3		65,532	0	0	6,641
	W	535,100	23.5		62,600	0	94	6,709
	CANADA	2,278,600	100.0	0	243,182	69.0	300	23,976
6	A	367,900	16.1	2,150	38,300	49.0	33	4,307
	Q	617,400	27.1	0	75,750	75.0	242	12,754
	O	758,200	33.3	0	65,532	0	0	9,548
	W	535,100	23.5	0	62,600	0	114	8,211
	CANADA	2,278,600	100.0	2,150	243,182	124.0	389	34,820

TABLE 7.4

SUMMARY OF INCREASED ANNUAL ENERGY/UTILITIES REQUIREMENTS

CASE		REGION	INCREASED ANNUAL ENERGY REQUIREMENTS				TOTAL FUEL + ELEC + STEAM	
			FUEL 10^6 BTU	ELECTRICITY 10^3 KW-h	STEAM 10^3 LB.	COOLING WATER 10^6 USG	10^6 BTU	FOE (BBL)
1	#2 FUEL	A	244,980	4,747	19,503	357	311,949	49,516
	OIL AND	Q	590,166	10,824	138,711	1,177	837,120	132,876
	LIGHTER	O	0	0	0	0	0	0
	0.3 WT.% S	W	64,009	797	- 2,798	104	69,184	10,982
	MAX.	CANADA	899,155	16,368	155,416	1,638	1,218,253	193,374
2	#2 FUEL	A	1,076,882	19,894	96,323	1,756	1,372,143	217,800
	OIL AND	Q	1,690,654	28,769	178,131	3,073	2,156,473	342,297
	LIGHTER	O	1,301,743	19,991	- 23,902	1,997	1,477,747	234,563
	0.1 WT.% S	W	909,950	14,204	- 14,591	1,410	1,036,496	164,523
	MAX.	CANADA	4,978,329	82,858	235,961	8,236	6,042,859	959,183
3	#2 FUEL OIL	A	- 103,697	111,352	-1,131,653	1,569	- 121,826	- 19,337
	AND LIGHTER	Q	-2,655,177	208,901	-2,506,477	- 23	-3,072,643	-487,721
	0.3 WT.% S MAX. +	O	-1,624,459	143,553	-1,503,811	842	-1,692,737	-268,688
	H-OIL LOW	W	- 340,381	151,557	-1,124,658	1,347	50,528	8,020
	CONVERSION	CANADA	-4,723,714	615,363	-6,266,599	3,735	-4,836,678	-767,726
4	#2 FUEL OIL	A	2,415,176	147,305	-1,043,947	6,467	2,844,282	451,473
	AND LIGHTER	Q	1,687,367	270,035	-2,395,778	8,375	1,991,939	316,180
	0.1 WT.% S MAX. +	O	- 426,134	148,945	-1,548,977	2,665	- 485,657	- 77,088
	H-OIL LOW	W	264,943	159,985	-1,141,394	2,308	723,394	114,824
	CONVERSION	CANADA	3,941,352	726,270	-6,130,096	19,815	5,073,958	805,389
5	#2 FUEL OIL	A	520,828	155,760	-1,027,953	3,315	1,050,475	166,742
	AND LIGHTER	Q	- 135,789	312,676	-2,397,525	7,127	593,451	94,196
	0.3 WT.% S MAX. +	O	-2,045,983	170,985	-1,473,611	355	-1,809,741	-287,260
	H-OIL HIGH	W	- 691,996	174,239	-1,061,767	668	- 11,374	- 1,805
	CONVERSION	CANADA	-2,352,940	813,660	-5,960,856	11,465	- 177,189	- 28,125
6	#2 FUEL OIL	A	3,166,326	193,429	- 942,883	8,441	4,157,731	659,957
	AND LIGHTER	Q	4,341,303	376,258	-2,270,003	15,792	5,833,881	926,013
	0.1 WT.% S MAX. +	O	- 635,399	193,333	-1,495,886	2,539	- 197,952	- 31,421
	H-OIL HIGH	W	31,233	195,812	-1,064,215	1,834	925,133	146,846
	CONVERSION	CANADA	6,902,469	958,832	-5,772,987	28,606	10,718,793	1,701,395

NOTES: Electricity: 1 KW = 10,000 BTU; Steam: 1 lb. = 1,000 BTU; Cooling water not included in the TOTAL.

"-" denotes a decreased requirement.

Fuel Oil: 6.3 MMBTU/BBL

TABLE 7.5

SUMMARY OF INCREASED ANNUAL OPERATING COSTS FOR UTILITIES AND MATERIALS

CASE		REGION	OPERATING MATERIALS				TOTAL MM $
			ENERGY MM $	COOLING WATER MM $	CATALYST MM $	CHEMICALS MM $	
1	#2 FUEL OIL AND LIGHTER 0.3 WT.% S. MAX.	A	1.61	0.04	0.04	0	1.69
		Q	3.86	0.12	0.10	0	4.08
		O	0	0	0	0	0
		W	0.19	0.01	0.01	0	0.21
		CANADA	5.66	0.17	0.15	0	5.98
2	#2 FUEL OIL AND LIGHTER 0.1 WT.% S. MAX.	A	7.13	0.18	0.13	- 0.01	7.43
		Q	9.65	0.31	0.28	- 0.01	10.23
		O	5.59	0.20	0.21	- 0.01	5.99
		W	2.93	0.14	0.14	- 0.01	3.20
		CANADA	25.30	0.83	0.76	- 0.04	26.85
3	#2 FUEL OIL AND LIGHTER 0.3 WT.% S. MAX. + H-OIL LOW CONVERSION	A	- 3.31	0.16	8.46	- 0.03	5.28
		Q	-23.63	0	18.38	- 0.08	- 5.33
		O	-11.55	0.09	8.77	- 0.04	- 2.73
		W	- 4.37	0.14	8.71	- 0.03	4.45
		CANADA	-42.86	0.39	44.32	- 0.18	1.67
4	#2 FUEL OIL AND LIGHTER 0.1 WT.% S. MAX. + H-OIL LOW CONVERSION	A	12.15	0.65	8.62	- 0.03	21.39
		Q	- 1.30	0.85	18.66	- 0.07	18.14
		O	- 6.92	0.27	8.93	- 0.06	2.22
		W	- 2.48	0.23	8.81	- 0.03	6.53
		CANADA	1.45	2.00	45.02	- 0.19	48.28
5	#2 FUEL OIL AND LIGHTER 0.3 WT.% S. MAX. + H-OIL HIGH CONVERSION	A	2.34	0.33	10.08	- 0.03	12.72
		Q	- 8.92	0.72	20.64	- 0.06	12.38
		O	-12.24	0.04	14.29	- 0.05	2.04
		W	- 4.54	0.07	13.50	- 0.05	8.98
		CANADA	-23.36	1.16	58.51	- 0.19	36.12
6	#2 FUEL OIL AND LIGHTER 0.1 WT.% S. MAX. + H-OIL HIGH CONVERSION	A	18.52	0.85	10.18	- 0.02	29.53
		Q	14.20	1.59	20.93	- 0.06	36.66
		O	- 6.15	0.26	14.56	- 0.07	8.60
		W	- 1.94	0.19	13.63	- 0.05	11.83
		CANADA	24.63	2.89	59.30	- 0.20	96.62

NOTE: "-" denotes a decrease.

TABLE 7.6

SUMMARY OF CAPITAL INVESTMENT FOR CANADA

CASE	ATLANTIC	QUEBEC	ONTARIO	WESTERN	CANADA
1	0	0	0	0	0
2	42.59	3.31	2.07	4.43	52.4
3	307.88	569.79	372.00	469.56	1,719.23
4	341.19	594.15	373.71	472.76	1,781.81
5	343.42	640.59	415.37	480.90	1,880.28
6	376.54	692.93	417.31	484.09	1,970.87

TABLE 7.7.1

SUMMARY OF CAPITAL INVESTMENT & INCREASED ANNUAL OPERATING COSTS

CASE: 1

REGION	ATLANTIC	QUEBEC	ONTARIO	WESTERN	CANADA
CRUDE RATE, BPCD	220,692	484,623	565,954	534,463	1,805,732
I. CAPITAL INVESTMENT, MM$	0	0	0	0	0
II. INCREASED ANNUAL OPERATING COSTS, MM$/YR.					
1. Annual Capital Charge	0	0	0	0	0
2. Fixed Costs					
(i) Operating Personnel	0	0	0	0	0
(ii) Maintenance	0	0	0	0	0
(iii) General, Sales, Administration	0	0	0	0	0
3. Decreased Feed Credit					
(i) Crude @ 34.0 $/B	0	0	0	0	0
(ii) " " 30.0 $/B	0	0	0	0	0
(iii) " " 35.0 $/B	0	0	0	0	0
(iv) " " 40.0 $/B	0	0	0	0	0
4. Increased Product Credit*	0.51	- 0.55	0	0.16	0.12
(Decreased HFO, 10^3B/YR.)	(0)	(0)	(0)	(0)	(0)
(Decreased Resid/Pitch, 10^3B/YR.)	(0)	(0)	(0)	(0)	(0)
5. Increased Energy/Utility Cost	1.65	3.98	0	0.20	5.83
6. Increased Cat. & Chem. Cost	0.04	0.10	0	0.01	0.15
III. Total of II; MM$/YR.					
1. Total of 1+2+3(i)+4+5+6	2.20	3.53	0	0.37	6.10
2. Total of 1+2+3(ii)+4+5+6	2.20	3.53	0	0.37	6.10
3. Total of 1+2+2(iii)+4+5+6	2.20	3.53	0	0.37	6.10
4. Total of 1+2+3(iv)+4+5+6	2.20	3.53	0	0.37	6.10

NOTES:
1. All costs are in millions of dollars per year.
2. "-" denotes a credit.
* Excluding HFO & Resid/Pitch.

TABLE 7.7.2

SUMMARY OF CAPITAL INVESTMENT & INCREASED ANNUAL OPERATING COSTS

CASE: 2

REGION	ATLANTIC	QUEBEC	ONTARIO	WESTERN	CANADA
CRUDE RATE, BPCD	220,692	484,623	565,954	534,463	1,805,732
I. CAPITAL INVESTMENT, MM$	42.59	3.31	2.07	4.43	52.40
II. INCREASED ANNUAL OPERATING COSTS, MM$/YR.					
1. Annual Capital Charge	10.65	0.83	0.52	1.11	13.11
2. Fixed Costs					
(i) Operating Personnel	1.35	0.68	0.75	1.69	4.47
(ii) Maintenance	1.28	0.10	0.06	0.13	1.57
(iii) General, Sales, Administration	1.49	0.12	0.07	0.16	1.84
3. Decreased Feed Credit					
(i) Crude @ 34.0 $/B	0	0	0	0	0
(ii) " " 30.0 $/B	0	0	0	0	0
(iii) " " 35.0 $/B	0	0	0	0	0
(iv) " " 40.0 $/B	0	0	0	0	0
4. Increased Product Credit*	- 0.19	- 0.79	- 0.40	- 1.40	- 2.78
(Decreased HFO, 10^3B/YR.)	(0)	(0)	(0)	(0)	(0)
(Decreased Resid/Pitch, 10^3B/YR.)	(0)	(0)	(0)	(0)	(0)
5. Increased Energy/Utility Cost	7.31	9.96	5.79	3.07	26.13
6. Increased Cat. & Chem. Cost	0.13	0.27	0.20	0.13	0.73
III. Total of II; MM$/YR.					
1. Total of 1+2+3(i)+4+5+6	22.02	11.17	6.99	4.89	45.07
2. Total of 1+2+3(ii)+4+5+6	22.02	11.17	6.99	4.89	45.07
3. Total of 1+2+3(iii)+4+5+6	22.02	11.17	6.99	4.89	45.07
4. Total of 1+2+3(iv)+4+5+6	22.02	11.17	6.99	4.89	45.07

NOTES:
1. All costs are in millions of dollars per year.
2. "-" denotes a credit.

* Excluding HFO & Resid/Pitch.

TABLE 7.7.3

SUMMARY OF CAPITAL INVESTMENT & INCREASED ANNUAL OPERATING COSTS

CASE: 3

REGION	ATLANTIC	QUEBEC	ONTARIO	WESTERN	CANADA
CRUDE RATE, BPCD	176,044	388,986	515,422	499,725	1,580,177
I. CAPITAL INVESTMENT, MM$	307.88	569.79	372.00	469.56	1,719.23
II. INCREASED ANNUAL OPERATING COSTS, MM$/YR.					
1. Annual Capital Charge	76.97	142.45	93.00	117.39	429.81
2. Fixed Costs					
(i) Operating Personnel	3.30	7.12	4.65	16.52	31.59
(ii) Maintenance	9.24	17.09	11.16	14.09	51.58
(iii) General, Sales, Administration	10.76	19.94	13.02	16.43	60.15
3. Decreased Feed Credit					
(i) Crude @ 34.0 $/B	- 545.02	-1,184.46	- 627.10	- 431.10	-2,787.68
(ii) " " 30.0 $/B	- 479.84	-1,044.83	- 553.33	- 380.38	-2,458.38
(iii) " " 35.0 $/B	- 561.32	-1,219.37	- 645.55	- 443.78	-2,870.02
(iv) " " 40.0 $/B	- 642.80	-1,393.91	- 737.77	- 507.17	-3,281.65
4. Increased Product Credit*	- 14.19	- 25.17	- 28.61	- 16.00	- 83.97
(Decreased HFO, 10^3B/YR.)	(15,525)	(33,365)	(18,507)	(9,055)	(76,450)
(Decreased Resid/Pitch, 10^3B/YR.)	(0)	(0)	(0)	(2,762)	(2,762)
5. Increased Energy/Utility Cost	- 3.15	- 23.63	- 11.46	- 4.23	- 42.47
6. Increased Cat. & Chem. Cost	8.43	18.30	8.74	8.68	44.15
III. Total of II; MM$/YR.					
1. Total of 1+2+3(i)+4+5+6	- 453.66	-1,028.36	- 536.60	- 278.22	-2,296.84
2. Total of 1+2+3(ii)+4+5+6	- 388.48	- 888.73	- 462.83	- 227.50	-1,967.54
3. Total of 1+2+3(iii)+4+5+6	- 469.96	-1,063.27	- 555.05	- 290.90	-2,379.18
4. Total of 1+2+3(iv)+4+5+6	- 551.44	-1,237.81	- 647.27	- 354.29	-2,790.81

NOTES:
1. All costs are in millions of dollars per year.
2. "-" denotes a credit.

* Excluding HFO & Resid/Pitch.

TABLE 7.7.4

SUMMARY OF CAPITAL INVESTMENT & INCREASED ANNUAL OPERATING COSTS

CASE: 4

REGION	ATLANTIC	QUEBEC	ONTARIO	WESTERN	CANADA
CRUDE RATE, BPCD	176,044	388,986	515,422	499,725	1,580,177
I. CAPITAL INVESTMENT, MM$	341.09	594.15	373.71	472.76	1,781.81
II. INCREASED ANNUAL OPERATING COSTS, MM$/YR.					
1. Annual Capital Charge	85.30	148.54	93.43	118.19	445.46
2. Fixed Costs					
(i) Operating Personnel	6.37	7.12	4.65	16.52	34.66
(ii) Maintenance	10.24	17.82	11.21	14.18	53.45
(iii) General, Sales, Administration	11.94	20.80	13.08	16.55	62.37
3. Decreased Feed Credit					
(i) Crude @ 34.0 $/B	- 537.00	-1,170.63	- 627.10	- 431.10	-2,765.83
(ii) " " 30.0 $/B	- 471.82	-1,031.00	- 553.33	- 380.38	-2,436.53
(iii) " " 35.0 $/B	- 553.30	-1,205.53	- 645.55	- 443.78	-2,848.15
(iv) " " 40.0 $/B	- 634.78	-1,380.07	- 737.77	- 507.17	-3,259.79
4. Increased Product Credit*	- 24.20	- 42.06	- 21.84	- 15.55	- 103.65
(Decreased HFO, 10^3B/YR.)	(15,525)	(33,365)	(18,507)	(9,055)	(76,452)
(Decreased Resid/Pitch, 10^3B/YR.)	(0)	(0)	(0)	(2,762)	(2,762)
5. Increased Energy/Utility Cost	12.80	- 0.45	- 6.65	- 2.25	3.45
6. Increased Cat. & Chem. Cost	8.59	18.59	8.87	8.78	44.83
III. Total of II; MM$/YR.					
1. Total of 1+2+3(i)+4+5+6	- 425.96	-1,000.27	- 524.35	- 274.68	-2,225.26
2. Total of 1+2+3(ii)+4+5+6	- 360.78	- 860.64	- 450.58	- 223.96	-1,895.96
3. Total of 1+2+3(iii)+4+5+6	- 442.26	-1,035.17	- 542.80	- 287.36	-2,307.59
4. Total of 1+2+3(iv)+4+5+6	- 523.74	-1,209.71	- 635.02	- 350.75	-2,719.22

NOTES:
1. All costs are in millions of dollars per year.
2. "-" denotes a credit.

* Excluding HFO & Resid/Pitch.

TABLE 7.7.5

SUMMARY OF CAPITAL INVESTMENT & INCREASED ANNUAL OPERATING COSTS

CASE: 5

REGION	ATLANTIC	QUEBEC	ONTARIO	WESTERN	CANADA
CRUDE RATE, BPCD	168,721	376,039	494,102	494,221	1,533,083
I. CAPITAL INVESTMENT, MM$	343.42	640.59	415.37	480.90	1,880.28
II. INCREASED ANNUAL OPERATING COSTS, MM$/YR.					
1. Annual Capital Charge	85.86	160.15	103.84	120.23	470.08
2. Fixed Costs					
(i) Operating Personnel	5.02	7.12	4.65	16.52	33.31
(ii) Maintenance	10.30	19.22	12.46	14.43	56.41
(iii) General, Sales, Administration	12.02	22.42	14.54	16.83	65.81
3. Decreased Feed Credit					
(i) Crude @ 34.0 $/B	- 628.94	-1,330.79	- 891.68	- 499.40	-3,350.81
(ii) " " 30.0 $/B	- 553.06	-1,172.25	- 786.78	- 440.65	-2,952.74
(iii) " " 35.0 $/B	- 647.91	-1,370.42	- 917.91	- 514.09	-3,450.33
(iv) " " 40.0 $/B	- 742.75	-1,568.59	-1,049.04	- 587.53	-3,947.91
4. Increased Product Credit*	- 31.61	- 65.42	- 26.74	- 22.74	- 146.51
(Decreased HFO, 10^3B/YR.)	(17,548)	(34,194)	(23,255)	(5,897)	(80,894)
(Decreased Resid/Pitch, 10^3B/YR.)	(1,076)	(5,093)	(2,663)	(8,129)	(16,961)
5. Increased Energy/Utility Cost	2.67	- 8.20	- 12.20	- 4.47	- 22.20
6. Increased Cat. & Chem. Cost	10.05	20.57	14.24	13.45	58.31
III. Total of II; MM$/YR.					
1. Total of 1+2+3(i)+4+5+6	- 534.63	-1,174.93	- 780.89	- 345.15	-2,835.60
2. Total of 1+2+3(ii)+4+5+6	- 458.75	-1,016.39	- 675.99	- 286.40	-2,437.53
3. Total of 1+2+3(iii)+4+5+6	- 553.60	-1,214.56	- 807.12	- 359.84	-2,935.12
4. Total of 1+2+3(iv)+4+5+6	- 648.44	-1,412.73	- 938.25	- 433.28	-3,432.70

NOTES:

1. All costs are in millions of dollars per year.
2. "-" denotes a credit.

* Excluding HFO & Resid/Pitch.

TABLE 7.7.6

SUMMARY OF CAPITAL INVESTMENT & INCREASED ANNUAL OPERATING COSTS

CASE: 6

REGION	ATLANTIC	QUEBEC	ONTARIO	WESTERN	CANADA
CRUDE RATE, BPCD	168,721	376,039	494,102	494,221	1,533,083
I. CAPITAL INVESTMENT, MM$	376.54	692.93	417.31	484.09	1,970.87
II. INCREASED ANNUAL OPERATING COSTS, MM$/YR.					
1. Annual Capital Charge	94.14	173.23	104.33	121.02	492.72
2. Fixed Costs					
(i) Operating Personnel	6.32	7.12	4.65	16.52	34.66
(ii) Maintenance	11.30	20.79	12.52	14.52	59.13
(iii) General, Sales, Administration	13.18	24.25	14.61	16.94	68.98
3. Decreased Feed Credit					
(i) Crude @ 34.0 $/B	- 620.51	-1,316.61	- 891.68	- 499.40	-3,328.20
(ii) " " 30.0 $/B	- 544.63	-1,158.08	- 786.78	- 440.65	-2,930.14
(iii) " " 35.0 $/B	- 639.48	-1,356.24	- 917.91	- 514.09	-3,427.72
(iv) " " 40.0 $/B	- 734.33	-1,554.41	-1,049.04	- 587.53	-3,925.31
4. Increased Product Credit*	- 43.01	- 83.24	- 28.19	- 27.45	- 181.94
(Decreased HFO, 10^3B/YR.)	(17,548)	(34,194)	(23,255)	(5,897)	(80,894)
(Decreased Resid/Pitch, 10^3B/YR.)	(1,076)	(5,093)	(2,663)	(8,129)	(16,961)
5. Increased Energy/Utility Cost	19.37	15.79	- 5.89	- 1.75	27.52
6. Increased Cat. & Chem. Cost	10.15	20.87	14.49	13.58	59.09
III. Total of II; MM$/YR.					
1. Total of 1+2+3(i)+4+5+6	- 509.01	-1,137.85	- 775.16	- 346.02	-2,768.04
2. Total of 1+2+3(ii)+4+5+6	- 433.13	- 979.32	- 670.26	- 287.27	-2,369.98
3. Total of 1+2+3(iii)+4+5+6	- 527.98	-1,177.48	- 801.39	- 360.71	-2,867.56
4. Total of 1+2+3(iv)+4+5+6	- 622.83	-1,375.65	- 932.52	- 434.15	-3,365.15

NOTES:
1. All costs are in millions of dollars per year.
2. "-" denotes a credit.
* Excluding HFO & Resid/Pitch.

8.0 REFERENCES

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APPENDIX I

TERMS OF REFERENCE

1. Appendix "A" - Statement of Work of Contract issued by Supply and Services Canada to MHG International Ltd., File No. 53SS.KE145-2-0754.

2. Portion of letter from MHG International Ltd. to Supply and Services Canada dated January 7, 1983.

APPENDIX "A"

53SS.KE145-2-0734
Serial 0SS82-00166

STATEMENT OF WORK:

INTRODUCTION

Canadian petroleum refineries process about 700 million barrels of crude oil into various grades of petroleum products. Some desulphurization of the crude oil via the hydrodesulphurization technique takes place, and about 22% of the sulphur is recovered as elemental sulphur. However, the major part of the sulphur in crude oil remains with the products and this sulphur is emitted to the atmosphere as sulphur oxide when the products are used.

There are about 900,000 tons of sulphur in the crude oils processed every year in Canada.

About 200,000 tonnes are recovered as elemental sulphur in sulphur plants and 600,000 tonnes of sulphur are emitted to the atmosphere (or 1.2 million tonnes of SO_2) after combustion of the petroleum products. Road asphalt contains about 100,000 tonnes of sulphur.

About 600,000 tonnes of sulphur are released by the combustion of the finished products of which about 100,000 tonnes are emitted by using petroleum products as fuel at the refineries. It has been further estimated that about 420,000 tonnes of sulphur are distributed in the heavy fuel oils which are marketed in Canada.

The study will investigate the effect of reducing the sulphur content of fuels as follows:

1. No. 2 fuel oils and lighter will be limited to a maximum sulphur content of 0.3 wt% and 0.1 wt%.
2. All fuel oils heavier than No. 2 fuel oil will be limited to a maximum sulphur content of
   (a) 1.0 wt%
   (b) 0.5 wt%
3. Impact of item 2 on the sulphur contents of No. 2 fuel oil and lighter
4. Combination of items 1 and 2

Study

The study will use the industry's 1981 operations as the reference case. The information for this will come from sources such as Statistics Canada, the federal department of EMR, the National Energy Board and the Canadian Energy Research Institute. In addition the Air Pollution Control Directorate will provide on a confidential basis the 1981 monitoring program on product volumes and sulphur contents.

The 1981 data base will be adjusted to meet separately the levels of sulphur content of fuel oils as specified in the introduction. Refinery fuel oil needs are to follow these sulphur limits. The study will rely, in the main, on the results produced by the use of the contractor's refinery process simulator covering the four regions of Canada.

The residue desulphurization system, using the H-Oil process shall be incorporated into the current process simulator. This residue desulphurization system shall contain (see also attached refinery diagram) the following:

a) Intermediate storage and pumping facilities for virgin vacuum residue

b) Complete RHDS facilities including sulphur recovery facilities, hydrogen facilities and sour water stripper and recovery of

   1) product gases
   2) naphtha for continued processing at the catalytic reformers
   3) light oil for inclusion into diesel fuel or No. 2 fuel

c) Withdrawal and continued processing of the hydrocracked (atmospheric) residue through a process heater and flash separator. The vapors of the flash separator will be processed through the existing refinery vacuum tower and the residue from the flash separator will be used for refinery fuel oil and heavy fuel oil sales.

d) Fuel characteristics to be developed for the hydrocracker-naphtha, light oil and vacuum residue enabling proper handling by the process simulator for continued processing and blending.

e) It is anticipated that this overall process configuration will reduce crude oil requirements. On account of this the contractor should meet, for the various desulphurization schemes, only the 1981 product output for the distillate fuels.

1) Annual* reduction of sulphur caused by the changes in fuel specification; broken down for:

   a) own fuel consumption
   b) saleable heavy fuel oil production
   c) light fuel oils

2) Investment for new facilities at each petroleum refinery to meet each specified sulphur level as outlined in the Introduction for items 1 to 4 (incl.). This should include sulphur recovery facilities with a recovery efficiency of 99% minimum where the sulphur production is 100 TD or more. For sulphur production rates less than 100 TD recovery efficiency should be 97.5% at least.

3) Revised annual* crude oil requirements.

4) Increased annual* energy requirements specified for fuel**, electricity**, steam** and cooling water.

5) Increased cost of operating materials such as energy sources, cooling water, catalyst, chemicals. Unit cost by contractor.

6) Increased annual* operating costs from:

   1. Capital charge - 25% on investment

   2. Crude oil cost, $/BBL

      a) cost prevailing at regions for 1981 mid-summer.
      b) other values of 30, 35 and 40.

3. Cost and volume of additional energy requirements by processing unit, detailed by Contractor.

4. Fixed annual operating costs, determined by Contractor.

Operating personnel	- $/yr per man
Supervisory/Techn. Personnel	- 25% of operating employee costs
Maintenance	- 3% of Capital Cost
General, Sales, Administrative, Taxes, Insurance	- 3.5% of Capital Cost

7. Credit for sulphur (Contractor to estimate sulphur sale price).

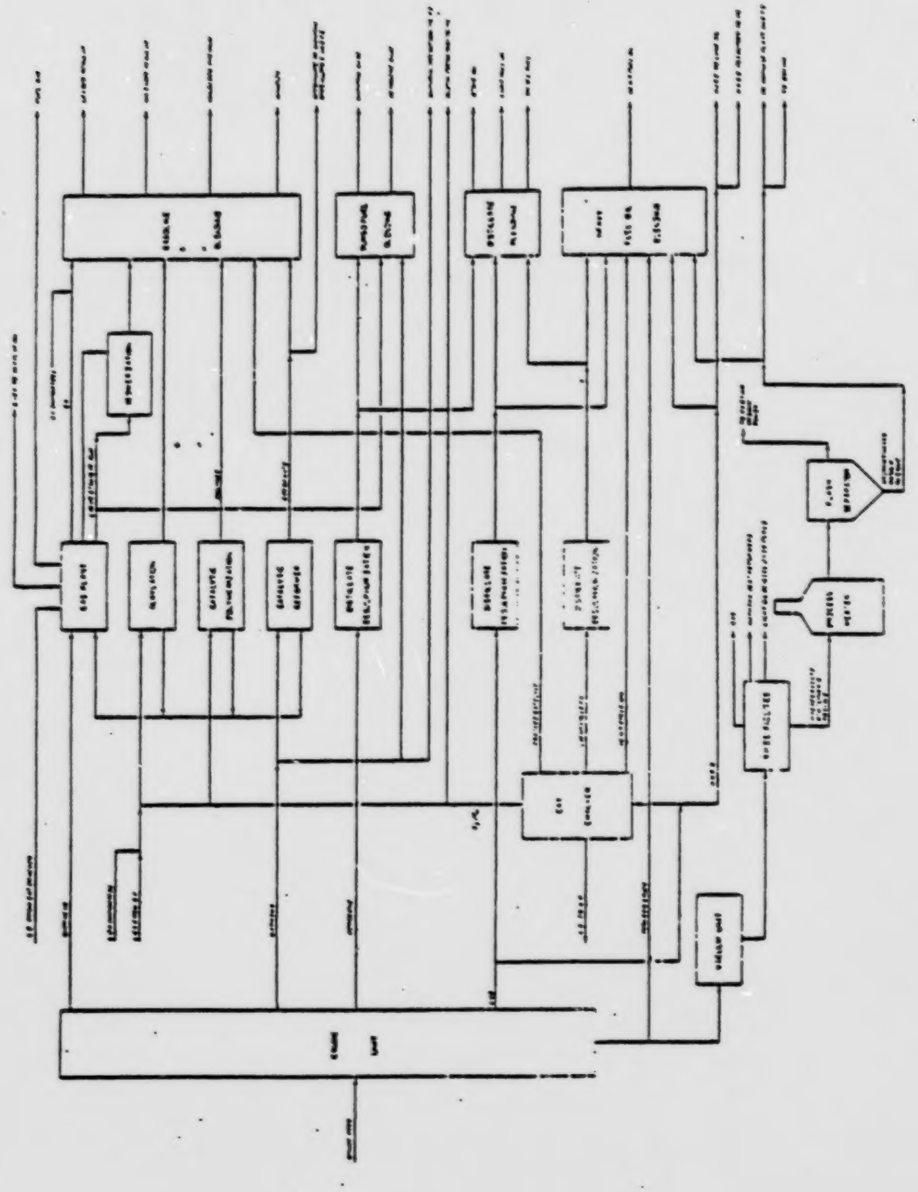
8. Capital and operating cost requirements will be based on mid-year 1982. These costs should be capable of extrapolation for a period of 5 years using appropriate indices such as the Nelson Construction Index and the Labour Index.

These above aspects to be backed up with adequate detailed costs and other related information leading to the above detailed derivations and to be reported.

* annual - 325 days per year
** fuel - 6.3 million BTU per Barrel
** electricity - 1 kwh - 10,000 BTU
** steam - 1 lb - 1,000 BTU

APPENDIX "A"

53SS.KE145-2-0734
Serial 05S82-00166



MHG International Ltd.
PROCESS PLANT DESIGN AND CONSTRUCTION
CALGARY TORONTO MONTREAL

January [illegible], 1983

Department of Supply and Services
Science Centre
12C1, Place du Portage
Phase III
Hull, Quebec
K1A 0S5

Attn: Mr. D. Ducharme
Science Procurement Officer

Gentlemen:

RE: STUDY ON PETROLEUM FUEL DESULPHURIZATION
IN PETROLEUM INDUSTRY

DSS FILE NO: 53SS.KE145-2-0734

MHG REF: MHP 249

We are in receipt of and thank you for your above referenced Request for Proposal.

We are pleased to have the opportunity to quote for this work and refer you to the following study perviously executed for D.O.E. in this particular area by MHG as a demonstration of our capabilities to carry out this study:

Study on Fuel Oil Desulphurization in the Petroleum Industry
for Environment Canada DSS File No. 37SS.KE204-0-0516
MHG Ref. FED 829 September 1981

This letter formulates our technical and price proposal for this work which is principally an extension to the scope of the aforementioned study.

..../2

EASTERN DIVISION, 2 ST. CLAIR AVE. EAST, SUITE 400, TORONTO, ONTARIO, CANADA M4T 2T5 · TELEPHONE (416) 961-7600 · TELEX 06-22613

Scope of Work

The scope of work to be undertaken in this study will be to evaluate the effects upon refinery operations of reducing the sulphur contents of the various grades of fuel oil produced. The study will use the year 1981 as the base case year and will encompass all of the refineries that were operating in that year. Since individual refinery operating data is not available, the study will examine the effects for Canada as a whole on a regional basis. It is proposed to adopt the same strategy as used in previous studies of dividing the country into four regions namely, Atlantic region, Quebec region, Ontario and Western regions based upon the predominant crude oil diet. Individual refineries within each region will be allocated their share of additional capacity based upon their own particular crude throughput ~~and refinery con-~~figuration.

The study will investigate the following six cases:

1. No. 2 fuel oils and lighter will be restricted to a maximum sulphur content of 0.3 wt. %. Fuel oils heavier than No. 2 fuel oil will be limited to the same sulphur content as was required in 1981.
2. Same as case 1 above except that LFO products restricted to 0.1 wt. % sulphur.
3. This case will assume an H-Oil unit to treat the vacuum column bottoms stream. A low conversion case of approximately 60 vol. % will be assumed (conversion being defined as the volume % of the feed material boiling up to 975°F converted into lighter products). At the same time, the LFO products will be limited to a maximum of 0.3 wt. % sulphur.
4. Same as case 3 above except that LFO products limited to 0.1 wt. % sulphur.
5. Same as case 3 except that a high conversion case will be used.
6. Same as case 3 except that a high conversion will be assumed and LFO products restricted to 0.1 wt. % sulphur.

The study will use the refinery process simulation model previously developed, however, the program will be modified to incorporate an H-Oil vacuum residue hydrodesulphurization unit and other changes aimed at minimising the need for hand calculation.

..../3

Scope of Work (Cont'd)

Since the inclusion of the H-Oil unit in cases 3 to 6 is anticipated to reduce the crude oil requirements, we will approach as near as practical the 1981 product slate. For these four cases, the study will duplicate only the 1981 product output for distillate fuels. All other products will be kept within the quality specifications and will match the 1981 outputs as closely as practicable.

The study will show the annual reduction of sulphur for each of the six cases and for each of the four regions and for Canada as a whole. These will be broken down into:

(a) the fuel consumed by the refineries

(b) the saleable heavy fuel oil

(c) the saleable light fuel oil

Investment for new facilities will be determined by firstly assessing the additional capacities required in each region and then allocating to each refinery within the region a proportion of new capacity in relation to its crude oil throughput and taking into account any existing capacity. In some cases, this approach may result in capacities of new units too small to be practical. In these cases, the smallest practical sized unit will be assumed for cost estimating purposes.

Increased energy requirements will be determined on a regional basis and will be used to calculate the increased operating costs. In addition to the energy cost, the operating costs will take into account such items as cooling water, catalysts, chemicals, maintenance and labour. Capital charges at 25% of investment will be included, and all costs including investment costs will be based upon mid-summer 1982.

APPENDIX II

Tables A II - 1 to 4

Incremental Annual Operating Cost for Feed, Products, Utilities, Catalysts and Chemicals (Suppl.) for Atlantic, Quebec, Ontario and Western Regions.

Tables A II - 5 to 10

Summary of Capital Investment and Increased Annual Operating Costs (Suppl.), Cases 1 to 6.

TABLE A II - 1

INCREASED ANNUAL OPERATING COST FOR FEED, PRODUCTS, UTILITIES, CATALYSTS AND CHEMICALS (SUPPL.)

ATLANTIC REGION

	CASE 1	CASE 2	CASE 3	CASE 4	CASE 5	CASE 6
INCREASED FEEDS :						
A. CRUDE FEED , BPCD	0	0	-44648	-44648	-51971	-51971
i. 34.00 $/bbl	0.00	0.00	-554.08	-554.08	-644.96	-644.96
ii. 30.00 $/bbl	0.00	0.00	-488.90	-488.90	-569.08	-569.08
iii. 35.00 $/bbl	0.00	0.00	-570.38	-570.38	-663.93	-663.93
iv. 40.00 $/bbl	0.00	0.00	-651.86	-651.86	-758.78	-758.78
B. NAPHTHA ,BPCD	0	0	584	1101	1033	1576
at 42.50 $/bbl	0.00	0.00	9.06	17.08	16.02	24.45
C. NATURAL GAS,MMSCFD	0	0	0	0	0	0
at 5.40 $/MSCF	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL INCREASED FEED COST						
i. 34.00 $/bbl	0.00	0.00	-545.02	-537.00	-628.94	-620.51
ii. 30.00 $/bbl	0.00	0.00	-479.84	-471.82	-553.06	-544.63
iii. 35.00 $/bbl	0.00	0.00	-561.32	-553.30	-647.91	-639.48
iv. 40.00 $/bbl	0.00	0.00	-642.80	-634.78	-742.75	-734.33
INCREASED PRODUCTS :						
A. Heavy Fuel Oil ,BPCD	0	0	-42533	-42533	-48076	-48076
at 34.00 $/bbl	0.00	0.00	-527.83	-527.83	-596.62	-596.62
B. Resid / Pitch ,BPCD	0	0	0	0	-2948	-2948
at 23.00 $/bbl	0.00	0.00	0.00	0.00	-24.75	-24.75
C. Fuel Gas ,MMBTU/day	-356	-1606	6442	9415	15626	18756
at 5.40 $/MMBTU	-0.70	-3.16	12.69	18.55	30.78	36.95
D. Naphtha ,BPCD	-4	149	-161	119	-164	133
at 42.50 $/bbl	-0.06	2.31	-2.50	1.85	-2.54	2.06
E. Sulfur, STPD	9.30	37.50	144.40	137.40	121.70	144.60
at 75.89 $/ST	0.26	1.04	4.00	3.81	3.37	4.01
TOTAL INCREASED PRODUCT COST	-0.51	0.19	-513.64	-503.64	-589.76	-578.36
INCREASED UTILITIES :						
A. Fuel ,MMBTU/year	244980	1076882	-103697	2415176	520828	3166326
at 5.40 $/MMBTU	1.32	5.81	-0.56	13.03	2.81	17.09
B. Electricity, 1000 kW-hr/year	4747	19894	111352	147305	155760	193429
at .037 $/kW-hr	0.18	0.74	4.12	5.45	5.76	7.16
C. Steam ,1000 lbs/year	19503	96323	-1131653	-1043947	-1027953	-942883
at 6.07 $/1000 lbs	0.12	0.58	-6.87	-6.34	-6.24	-5.72
D. Cooling Water , MM USG/year	357	1756	1569	6467	3315	8441
at 101.00 $/ MM USG	0.04	0.18	0.16	0.65	0.33	0.85
TOTAL INCREASED UTILITIES COST	1.65	7.31	-3.15	12.80	2.67	19.37
INCREASED CATALYSTS AND CHEMICALS :						
A. Catalysts	0.04	0.13	8.46	8.62	10.08	10.18
B. Chemicals	-0.00	-0.01	-0.03	-0.03	-0.03	-0.02
TOTAL INCREASED CATALYSTS AND CHEMICALS COST	0.04	0.13	8.43	8.59	10.05	10.15

Notes : "-" denotes decrease .
All costs are Million $/year.

TABLE A II - 2

INCREASED ANNUAL OPERATING COST FOR FEED, PRODUCTS, UTILITIES, CATALYSTS AND CHEMICALS (SUPPL.)

QUEBEC REGION

	CASE 1	CASE 2	CASE 3	CASE 4	CASE 5	CASE 6
INCREASED FEEDS :						
A. CRUDE FEED , BPCD	0	0	-95637	-95637	-108584	-108584
i. 34.00 $/bbl	0.00	0.00	-1186.86	-1186.86	-1347.53	-1347.53
ii. 30.00 $/bbl	0.00	0.00	-1047.23	-1047.23	-1188.99	-1188.99
iii. 35.00 $/bbl	0.00	0.00	-1221.76	-1221.76	-1387.16	-1387.16
iv. 40.00 $/bbl	0.00	0.00	-1396.30	-1396.30	-1585.33	-1585.33
B. NAPHTHA ,BPCD	0	0	0	0	0	0
at 42.50 $/bbl	0.00	0.00	0.00	0.00	0.00	0.00
C. NATURAL GAS,MMSCFD	0	0	1.4	9.5	9.8	18.1
at 4.68 $/MSCF	0.00	0.00	2.39	16.23	16.74	30.92
TOTAL INCREASED FEED COST						
i. 34.00 $/bbl	0.00	0.00	-1184.46	-1170.63	-1330.79	-1316.61
ii. 30.00 $/bbl	0.00	0.00	-1044.83	-1031.00	-1172.25	-1158.08
iii. 35.00 $/bbl	0.00	0.00	-1219.37	-1205.53	-1370.42	-1356.24
iv. 40.00 $/bbl	0.00	0.00	-1393.91	-1380.07	-1568.59	-1554.41
INCREASED PRODUCTS :						
A. Heavy Fuel Oil ,BPCD	0	0	-91410	-91410	-93681	-93681
at 34.00 $/bbl	0.00	0.00	-1134.40	-1134.40	-1162.58	-1162.58
B. Resid / Pitch ,BPCD	0	0	0	0	-13954	-13954
at 23.00 $/bbl	0.00	0.00	0.00	0.00	-117.14	-117.14
C. Fuel Gas ,MMBTU/day	-478	-2751	12685	17706	35750	41003
at 4.68 $/MMBTU	-0.82	-4.70	21.67	30.25	61.07	70.04
D. Naphtha ,BPCD	73	269	-251	214	-222	279
at 42.50 $/bbl	1.13	4.17	-3.89	3.32	-3.44	4.33
E. Sulfur, STPD	8.30	47.70	267.00	306.70	281.40	321.90
at 75.89 $/ST	0.23	1.32	7.40	8.50	7.79	8.92
TOTAL INCREASED PRODUCT COST	0.55	0.79	-1109.23	-1092.34	-1214.31	-1196.44
INCREASED UTILITIES :						
A. Fuel ,MMBTU/year	590166	1690654	-2655177	1687367	-135789	4341303
at 4.68 $/MMBTU	2.76	7.91	-12.43	7.90	-0.64	20.32
B. Electricity, 1000 kW-hr/year	10824	28769	208901	270035	312676	376258
at .0215 $/kW-hr	0.23	0.62	4.49	5.81	6.72	8.09
C. Steam ,1000 lbs/year	138711	178131	-2506477	-2395778	-2397525	-2270003
at 6.26 $/1000 lbs	0.87	1.12	-15.69	-15.00	-15.01	-14.21
D. Cooling Water , MM USG/year	1177	3073	-23	8375	7127	15792
at 101.00 $/ MM USG	0.12	0.31	-0.00	0.85	0.72	1.59
TOTAL INCREASED UTILITIES COST	3.98	9.96	-23.63	-0.45	-8.20	15.79
INCREASED CATALYSTS AND CHEMICALS :						
A. Catalysts	0.10	0.28	18.38	18.66	20.64	20.93
B. Chemicals	-0.00	-0.01	-0.08	-0.07	-0.06	-0.06
TOTAL INCREASED CATALYSTS AND CHEMICALS COST	0.10	0.27	18.30	18.59	20.57	20.87

Notes : "-" denotes decrease .
All costs are Million $/year.

TABLE A II - 3

INCREASED ANNUAL OPERATING COST FOR FEED, PRODUCTS, UTILITIES, CATALYSTS AND CHEMICALS (SUPPL.)

ONTARIO REGION

	CASE 1	CASE 2	CASE 3	CASE 4	CASE 5	CASE 6
INCREASED FEEDS :						
A. CRUDE FEED , BPCD	0	0	-50532	-50532	-71852	-71852
i. 34.00 $/bbl	0.00	0.00	-627.10	-627.10	-891.68	-891.68
ii. 30.00 $/bbl	0.00	0.00	-553.33	-553.33	-786.78	-786.78
iii. 35.00 $/bbl	0.00	0.00	-645.55	-645.55	-917.91	-917.91
iv. 40.00 $/bbl	0.00	0.00	-737.77	-737.77	-1049.04	-1049.04
B. NAPHTHA ,BPCD	0	0	0	0	0	0
at 42.50 $/bbl	0.00	0.00	0.00	0.00	0.00	0.00
C. NATURAL GAS,MMSCFD	0	0	0	0	0	0
at 3.96 $/MSCF	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL INCREASED FEED COST						
i. 34.00 $/bbl	0.00	0.00	-627.10	-627.10	-891.68	-891.68
ii. 30.00 $/bbl	0.00	0.00	-553.33	-553.33	-786.78	-786.78
iii. 35.00 $/bbl	0.00	0.00	-645.55	-645.55	-917.91	-917.91
iv. 40.00 $/bbl	0.00	0.00	-737.77	-737.77	-1049.04	-1049.04
INCREASED PRODUCTS :						
A. Heavy Fuel Oil ,BPCD	0	0	-50704	-50704	-63712	-63712
at 34.00 $/bbl	0.00	0.00	-629.24	-629.24	-790.67	-790.67
B. Resid / Pitch ,BPCD	0	0	0	0	-7296	-7296
at 23.00 $/bbl	0.00	0.00	0.00	0.00	-61.25	-61.25
C. Fuel Gas ,MMBTU/day	0	-3047	17348	9904	15447	12462
at 3.96 $/MMBTU	0.00	-4.40	25.07	14.32	22.33	18.01
D. Naphtha ,BPCD	0	251	-26	172	-14	298
at 42.50 $/bbl	0.00	3.89	-0.40	2.67	-0.22	4.62
E. Sulfur, STPD	0.00	33.00	142.30	175.30	167.30	200.60
at 75.89 $/ST	0.00	0.91	3.94	4.86	4.63	5.56
TOTAL INCREASED PRODUCT COST	0.00	0.40	-600.62	-607.40	-825.17	-823.72
INCREASED UTILITIES :						
A. Fuel ,MMBTU/year	0	1301743	-1624459	-426134	-2045983	-635393
at 3.96 $/MMBTU	0.00	5.15	-6.43	-1.69	-8.10	-2.52
B. Electricity, 1000 kW-hr/year	0	19991	143553	148945	170985	193333
at .0280 $/KW-hr	0.00	0.58	4.13	4.29	4.92	5.57
C. Steam ,1000 lbs/year	0	-23902	-1503811	-1548977	-1473611	-1495086
at 6.15 $/1000 lbs	0.00	-0.15	-9.25	-9.53	-9.06	-9.20
D. Cooling Water , MM USG/year	0	1997	842	2665	355	2539
at 101.00 $/ MM USG	0.00	0.20	0.09	0.27	0.04	0.26
TOTAL INCREASED UTILITIES COST	0.00	5.79	-11.46	-6.65	-12.20	-5.89
INCREASED CATALYSTS AND CHEMICALS :						
A. Catalysts	0.00	0.21	8.77	8.93	14.29	14.56
B. Chemicals	0.00	-0.01	-0.04	-0.06	-0.05	-0.07
TOTAL INCREASED CATALYSTS AND CHEMICALS COST	0.00	0.20	8.74	8.87	14.24	14.49

Notes : "-" denotes decrease .
All costs are Million $/year.

TABLE A II - 4

INCREASED ANNUAL OPERATING COST FOR FEED, PRODUCTS, UTILITIES, CATALYSTS AND CHEMICALS (SUPPL.)

WESTERN REGION

	CASE 1	CASE 2	CASE 3	CASE 4	CASE 5	CASE 6
INCREASED FEEDS :						
A. CRUDE FEED , BPCD	0	0	-34738	-34738	-40242	-40242
i. 34.00 $/bbl	0.00	0.00	-431.10	-431.10	-499.40	-499.40
ii. 30.00 $/bbl	0.00	0.00	-380.38	-380.38	-440.65	-440.65
iii. 35.00 $/bbl	0.00	0.00	-443.78	-443.78	-514.09	-514.09
iv. 40.00 $/bbl	0.00	0.00	-507.17	-507.17	-587.53	-587.53
B. NAPHTHA ,BPCD	0	0	0	0	0	0
at 42.50 $/bbl	0.00	0.00	0.00	0.00	0.00	0.00
C. NATURAL GAS,MMSCFD	0	0	0	0	0	0
at 2.97 $/MSCF	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL INCREASED FEED COST						
i. 34.00 $/bbl	0.00	0.00	-431.10	-431.10	-499.40	-499.40
ii. 30.00 $/bbl	0.00	0.00	-380.38	-380.38	-440.65	-440.65
iii. 35.00 $/bbl	0.00	0.00	-443.78	-443.78	-514.09	-514.09
iv. 40.00 $/bbl	0.00	0.00	-507.17	-507.17	-587.53	-587.53
INCREASED PRODUCTS :						
A. Heavy Fuel Oil ,BPCD	0	0	-24807	-24807	-16157	-16157
at 34.00 $/bbl	0.00	0.00	-307.85	-307.85	-200.51	-200.51
B. Resid / Pitch ,BPCD	0	0	-7568	-7568	-22270	-22270
at 23.00 $/bbl	0.00	0.00	-63.53	-63.53	-186.96	-186.96
C. Fuel Gas ,MMBTU/day	-224	-1992	11329	9598	17297	19378
at 2.97 $/MMBTU	-0.24	-2.16	12.28	10.40	18.75	21.01
D. Naphtha ,BPCD	1	191	42	101	41	167
at 42.50 $/bbl	0.02	2.96	0.65	1.57	0.64	2.59
E. Sulfur, STPD	2.50	21.50	110.80	129.30	121.10	139.20
at 75.89 $/ST	0.07	0.60	3.07	3.58	3.35	3.86
TOTAL INCREASED PRODUCT COST	-0.16	1.40	-355.39	-355.84	-364.72	-360.01
INCREASED UTILITIES :						
A. Fuel ,MMBTU/year	64009	909050	-340381	264943	-691996	31233
at 2.97 $/MMBTU	0.19	2.70	-1.01	0.79	-2.06	0.09
B. Electricity, 1000 kW-hr/year	797	14204	151557	159985	174239	195812
at .022 $/kW-hr	0.02	0.31	3.33	3.52	3.83	4.31
C. Steam ,1000 lbs/year	-2798	-14591	-1124658	-1141394	-1061767	-1064215
at 5.95 $/1000 lbs	-0.02	-0.09	-6.69	-6.79	-6.32	-6.33
D. Cooling Water , MM USG/year	104	1410	1347	2308	668	1834
at 101.00 $/ MM USG	0.01	0.14	0.14	0.23	0.07	0.19
TOTAL INCREASED UTILITIES COST	0.20	3.07	-4.23	-2.25	-4.47	-1.75
INCREASED CATALYSTS AND CHEMICALS :						
A. Catalysts	0.01	0.14	8.71	8.81	13.50	13.63
B. Chemicals	-0.00	-0.01	-0.03	-0.03	-0.05	-0.05
TOTAL INCREASED CATALYSTS AND CHEMICALS COST	0.01	0.13	8.68	8.78	13.45	13.58

Notes : "-" denotes decrease .
All costs are Million $/year.

TABLE A II-5

SUMMARY OF CAPITAL INVESTMENT & INCREASED ANNUAL OPERATING COSTS (SUPPL.)

CASE: 1

REGION	ATLANTIC	QUEBEC	ONTARIO	WESTERN	CANADA
CRUDE RATE, BPCD	220,692	484,623	565,954	534,463	1,805,732
I. CAPITAL INVESTMENT, MM$	0	0	0	0	0
II. INCREASED ANNUAL OPERATING COSTS, MM$/YR.					
1. Annual Capital Charge	0	0	0	0	0
2. Fixed Costs					
(i) Operating Personnel	0	0	0	0	0
(ii) Maintenance	0	0	0	0	0
(iii) General, Sales, Administration	0	0	0	0	0
3. Decreased Feed Credit					
(i) Crude @ 34.0 $/B ('81)	0	0	0	0	0
(ii) " " 30.0 $/B	0	0	0	0	0
(iii) " " 35.0 $/B	0	0	0	0	0
(iv) " " 40.0 $/B	0	0	0	0	0
4. Increased Product Credit**	0.51	- 0.55	0	0.15	0.12
5. Increased Energy/Utility Cost	1.65	3.98	0	0.20	5.85
6. Increased Cat. & Chem. Cost	0.04	0.10	0	0.01	0.15
III. Total of II; MM$/YR.					
1. Total of 1+2+3(i)+4+5+6	2.20	3.53	0	0.37	6.10
2. Total of 1+2+3(ii)+4+5+6	2.20	3.53	0	0.37	6.10
3. Total of 1+2+3(iii)+4+5+6	2.20	3.53	0	0.37	6.10
4. Total of 1+2+3(iv)+4+5+6	2.20	3.53	0	0.37	6.10
IV. INCREASED OPTG. COST/BBL CRUDE					
1. Case 3(i), $/B	0.03	0.02	0.00	0.00	0.01
2. Case 3(ii), "	0.03	0.02	0.00	0.00	0.01
3. Case 3(iii), "	0.03	0.02	0.00	0.00	0.01
4. Case 3(iv), "	0.03	0.02	0.00	0.00	0.01

NOTES: All costs are in MM$/year.

"-" denotes a credit.

** Including HFO and Resid/Pitch costs (debit).

TABLE A II-6

SUMMARY OF CAPITAL INVESTMENT & INCREASED ANNUAL OPERATING COSTS (SUPPL.)

CASE: 2

REGION	ATLANTIC	QUEBEC	ONTARIO	WESTERN	CANADA
CRUDE RATE, BPCD	220,692	484,623	565,954	534,463	1,805,732
I. CAPITAL INVESTMENT, MM$	42.59	3.31	2.07	4.43	52.40
II. INCREASED ANNUAL OPERATING COSTS, MM$/YR.					
1. Annual Capital Charge	10.65	0.83	0.52	1.11	13.11
2. Fixed Costs					
(i) Operating Personnel	1.35	0.68	0.75	1.69	4.47
(ii) Maintenance	1.28	0.10	0.06	0.13	1.57
(iii) General, Sales, Administration	1.49	0.12	0.07	0.16	1.84
3. Decreased Feed Credit					
(i) Crude @ 34.0 $/B ('81)	0	0	0	0	0
(ii) " " 30.0 $/B	0	0	0	0	0
(iii) " " 35.0 $/B	0	0	0	0	0
(iv) " " 40.0 $/B	0	0	0	0	0
4. Increased Product Credit**	- 0.19	- 0.79	- 0.40	- 1.40	- 2.78
5. Increased Energy/Utility Cost	7.31	9.96	5.79	3.07	26.13
6. Increased Cat. & Chem. Cost	0.13	0.27	0.20	0.13	0.73
III. Total of II; MM$/YR.					
1. Total of 1+2+3(i)+4+5+6	22.02	11.17	6.99	4.89	45.07
2. Total of 1+2+3(ii)+4+5+6	22.02	11.17	6.99	4.89	45.07
3. Total of 1+2+3(iii)+4+5+6	22.02	11.17	6.99	4.89	45.07
4. Total of 1+2+3(iv)+4+5+6	22.02	11.17	6.99	4.89	45.07
IV. INCREASED OPTG. COST/BBL CRUDE					
1. Case 3(i), $/B	0.27	0.06	0.03	0.03	0.07
2. Case 3(ii), "	0.27	0.06	0.03	0.03	0.07
3. Case 3(iii), "	0.27	0.06	0.03	0.03	0.07
4. Case 3(iv), "	0.27	0.06	0.03	0.03	0.07

NOTES: All costs are in MM$/year.

"-" denotes a credit.

** Including HFO and Resid/Pitch costs (debit).

TABLE A II-7

SUMMARY OF CAPITAL INVESTMENT & INCREASED ANNUAL OPERATING COSTS (SUPPL.)

CASE: 3

REGION	ATLANTIC	QUEBEC	ONTARIO	WESTERN	CANADA
CRUDE RATE, BPCD	176,044	388,986	515,422	499,725	1,580,177
I. CAPITAL INVESTMENT, MM$	307.88	569.79	372.00	469.56	1,719.23
II. INCREASED ANNUAL OPERATING COSTS, MM$/YR.					
1. Annual Capital Charge	76.97	142.45	93.00	117.39	429.81
2. Fixed Costs					
(i) Operating Personnel	3.30	7.12	4.65	16.52	31.59
(ii) Maintenance	9.24	17.09	11.16	14.09	51.58
(iii) General, Sales, Administration	10.76	19.94	13.02	16.43	60.15
3. Decreased Feed Credit					
(i) Crude @ 34.0 $/B ('81)	- 545.02	-1,184.46	- 627.10	- 431.10	-2,787.68
(ii) " " 30.0 $/B	- 479.84	-1,044.83	- 553.33	- 380.38	-2,458.38
(iii) " " 35.0 $/B	- 561.32	-1,219.37	- 645.55	- 443.78	-2,870.02
(iv) " " 40.0 $/B	- 642.80	-1,393.91	- 737.77	- 507.17	-3,281.65
4. Increased Product Credit**	513.64	1,109.23	600.62	355.39	2,578.88
5. Increased Energy/Utility Cost	- 3.15	- 23.63	- 11.46	- 4.23	- 42.47
6. Increased Cat. & Chem. Cost	8.43	18.30	8.74	8.68	44.15
III. Total of II; MM$/YR.					
1. Total of 1+2+3(i)+4+5+6	74.17	106.04	91.63	93.17	366.01
2. Total of 1+2+3(ii)+4+5+6	139.35	245.67	166.40	143.89	695.31
3. Total of 1+2+3(iii)+4+5+6	57.87	71.13	74.18	80.49	283.67
4. Total of 1+2+3(iv)+4+5+6	- 23.61	- 103.41	- 18.04	17.10	- 127.96
IV. INCREASED OPTG. COST/BBL CRUDE					
1. Case 3(i), $/B	1.15	0.75	0.49	0.51	0.63
2. Case 3(ii), "	2.17	1.73	0.88	0.79	1.21
3. Case 3(iii), "	0.90	0.50	0.39	0.44	0.49
4. Case 3(iv), "	- 0.37	- 0.01	- 0.10	- 0.09	- 0.22

NOTES: All costs are in MM$/year.

"-" denotes a credit.

** including HFO and Resid/Pitch costs (debit).

TABLE A II-8

SUMMARY OF CAPITAL INVESTMENT & INCREASED ANNUAL OPERATING COSTS (SUPPL.)

CASE: 4

REGION	ATLANTIC	QUEBEC	ONTARIO	WESTERN	CANADA
CRUDE RATE, BPCD	176,044	388,896	515,422	499,725	1,580,177
I. CAPITAL INVESTMENT, MM$	341.19	594.15	373.71	472.76	1,781.81
II. INCREASED ANNUAL OPERATING COSTS, MM$/YR.					
1. Annual Capital Charge	85.30	148.54	93.43	118.19	445.46
2. Fixed Costs					
(i) Operating Personnel	6.37	7.12	4.65	16.52	34.66
(ii) Maintenance	10.24	17.82	11.21	14.18	53.45
(iii) General, Sales, Administration	11.94	20.80	13.08	16.55	62.37
3. Decreased Feed Credit					
(i) Crude @ 34.0 $/B ('81)	- 537.00	-1,170.63	- 627.10	- 431.10	-2,765.83
(ii) " " 30.0 $/B	- 471.82	-1,031.00	- 553.33	- 380.38	-2,436.53
(iii) " " 35.0 $/B	- 553.30	-1,205.53	- 645.55	- 443.78	-2,848.16
(iv) " " 40.0 $/B	- 634.78	-1,380.07	- 737.77	- 507.17	-3,259.79
4. Increased Product Credit**	503.64	1,092.34	607.40	355.84	2,559.22
5. Increased Energy/Utility Cost	12.80	- 0.45	- 6.65	- 2.25	3.45
6. Increased Cat. & Chem. Cost	8.59	18.59	8.87	8.78	44.83
III. Total of II; MM$/YR.					
1. Total of 1+2+3(i)+4+5+6	101.88	134.13	104.89	96.71	437.61
2. Total of 1+2+3(ii)+4+5+6	167.06	273.76	178.66	147.43	766.91
3. Total of 1+2+3(iii)+4+5+6	85.58	99.23	86.44	84.03	355.28
4. Total of 1+2+3(iv)+4+5+6	4.10	- 75.31	- 5.78	20.64	- 56.35
IV. INCREASED OPTG. COST/BBL CRUDE					
1. Case 3(i), $/B	1.59	0.94	0.56	0.53	0.76
2. Case 3(ii), "	2.60	1.93	0.95	0.81	1.33
3. Case 3(iii), "	1.33	0.70	0.46	0.46	0.62
4. Case 3(iv), "	0.06	- 0.53	- 0.03	0.11	- 0.10

NOTES: All costs are in MM$/year.

"-" denotes a credit.

** Including HFO and Resid/Pitch costs (debit).

TABLE A II-9

SUMMARY OF CAPITAL INVESTMENT & INCREASED ANNUAL OPERATING COSTS (SUPPL.)

CASE: 5

REGION	ATLANTIC	QUEBEC	ONTARIO	WESTERN	CANADA
CRUDE RATE, BPCD	168,721	376,039	494,102	494,221	1,533,083
I. CAPITAL INVESTMENT, MM$	343.42	640.59	415.37	480.90	1,880.28
II. INCREASED ANNUAL OPERATING COSTS, MM$/YR.					
1. Annual Capital Charge	85.86	160.15	103.84	120.23	470.08
2. Fixed Costs					
(i) Operating Personnel	5.02	7.12	4.65	16.52	33.31
(ii) Maintenance	10.30	19.22	12.46	14.43	56.41
(iii) General, Sales, Administration	12.02	22.42	14.54	16.83	65.81
3. Decreased Feed Credit					
(i) Crude @ 34.0 $/B ('81)	- 628.94	-1,330.79	- 891.68	- 499.40	-3,350.81
(ii) " " 30.0 $/B	- 553.06	-1,172.25	- 786.78	- 440.65	-2,952.74
(iii) " " 35.0 $/B	- 647.91	-1,370.42	- 917.91	- 514.09	-3,450.33
(iv) " " 40.0 $/B	- 742.75	-1,568.59	-1,049.04	- 587.53	-3,947.91
4. Increased Product Credit**	589.76	1,214.31	825.17	364.72	2,993.96
5. Increased Energy/Utility Cost	2.67	- 8.20	- 12.20	- 4.47	- 22.20
6. Increased Cat. & Chem. Cost	10.05	20.57	14.24	13.45	58.31
III. Total of II; MM$/YR.					
1. Total of 1+2+3(i)+4+5+6	86.74	104.80	71.02	42.31	304.87
2. Total of 1+2+3(ii)+4+5+6	162.62	263.34	175.92	101.06	702.94
3. Total of 1+2+3(iii)+4+5+6	67.77	65.17	44.79	27.62	205.35
4. Total of 1+2+3(iv)+4+5+6	- 27.07	- 133.00	- 86.34	- 45.82	- 292.23
IV. INCREASED OPTG. COST/BBL CRUDE					
1. Case 3(i), $/B	1.41	0.76	0.39	0.23	0.54
2. Case 3(ii), "	2.64	1.92	0.98	0.56	1.26
3. Case 3(iii), "	1.10	0.47	0.25	0.15	0.37
4. Case 3(iv), "	- 0.44	- 0.97	- 0.48	- 0.25	- 0.52

NOTES: All costs are in MM$/year.

"-" denotes a credit.

** Including HFO and Resid/Pitch costs (debit).

TABLE A II-10

SUMMARY OF CAPITAL INVESTMENT & INCREASED ANNUAL OPERATING COSTS (SUPPL.)

CASE: 6

REGION	ATLANTIC	QUEBEC	ONTARIO	WESTERN	CANADA
CRUDE RATE, BPCD	168,721	376,039	494,102	494,221	1,533,083
I. CAPITAL INVESTMENT, MM$	376.54	692.93	417.31	484.09	1,970.87
II. INCREASED ANNUAL OPERATING COSTS, MM$/YR.					
1. Annual Capital Charge	94.14	173.23	104.33	121.02	492.72
2. Fixed Costs					
(i) Operating Personnel	6.37	7.12	4.65	16.52	34.66
(ii) Maintenance	11.30	20.79	12.52	14.52	59.13
(iii) General, Sales, Administration	13.18	24.25	14.61	16.94	68.98
3. Decreased Feed Credit					
(i) Crude @ 34.0 $/B ('81)	- 620.51	-1,316.61	- 891.68	- 499.40	-3,328.20
(ii) " " 30.0 $/B	- 544.63	-1,158.08	- 786.78	- 440.65	-2,930.14
(iii) " " 35.0 $/B	- 639.48	-1,356.24	- 917.91	- 514.09	-3,427.72
(iv) " " 40.0 $/B	- 734.33	-1,554.41	-1,049.04	- 587.53	-3,925.31
4. Increased Product Credit**	578.36	1,196.44	823.72	360.01	2,958.53
5. Increased Energy/Utility Cost	19.37	15.79	- 5.89	- 1.75	27.52
6. Increased Cat. & Chem. Cost	10.15	20.87	14.49	13.58	59.09
III. Total of II; MM$/YR.					
1. Total of 1+2+3(i)+4+5+6	112.36	141.88	76.75	41.44	372.43
2. Total of 1+2+3(ii)+4+5+6	188.24	300.41	181.65	100.19	770.49
3. Total of 1+2+3(iii)+4+5+6	93.39	102.25	50.52	26.75	272.91
4. Total of 1+2+3(iv)+4+5+6	- 1.46	- 95.92	- 80.61	- 46.69	- 224.68
IV. INCREASED OPTG. COST/BBL CRUDE					
1. Case 3(i), $/B	1.82	1.03	0.43	0.23	0.67
2. Case 3(ii), "	3.06	2.19	1.01	0.56	1.38
3. Case 3(iii), "	1.52	0.74	0.28	0.15	0.49
4. Case 3(iv), "	- 0.02	- 0.70	- 0.45	- 0.26	- 0.40

NOTES: All costs are in MM$/year.

"-" denotes a credit.

** Including HFO and Resid/Pitch costs (debit).

APPENDIX III

Increased Process Unit Capacities for Individual Refineries

Tables A III -	1 to 6	Atlantic Region,	Cases 1 to 6
" " " -	7 to 12	Quebec Region,	Cases 1 to 6
" " " -	13 to 18	Ontario Region,	Cases 1 to 6
" " " -	19 to 24	Western Region,	Cases 1 to 6

TABLE A III - 1

INCREASED PROCESS UNIT CAPACITIES FOR INDIVIDUAL REFINERIES

ATLANTIC REGION, CASE NO. 1

REFINERY CODE	CRUDE CAPACITY BPCD	%	DISTILLATE & GAS OIL HTU				H-OIL BPSD	HYDROGEN PLANT (97%) MMSCFSD	AMINE PLANT MMSCFSD	SULFUR PLANT STPSD	SOUR WATER STRIPPER BPSD
			KERO BPSD	LGO BPSD	LCO BPSD	HCO BPSD					
A-1	14,000	3.8									
A-3	83,900	22.8									
A-4	20,000	5.4									
A-5	250,000	68.0									
TOTAL	367,900	100.0	0	0	0	0	0	0	0	0	0

NOTES: On stream factor = 0.89

TABLE A III - 2

INCREASED PROCESS UNIT CAPACITIES FOR INDIVIDUAL REFINERIES

ATLANTIC REGION, CASE NO. 2

REFINERY CODE	CRUDE CAPACITY BPCD	%	DISTILLATE & GAS OIL HTU				H-OIL BPSD	HYDROGEN PLANT (97%) MMSCFSD	AMINE PLANT MMSCFSD	SULFUR PLANT STPSD	SOUR WATER STRIPPER BPSD
			KERO BPSD	LGO BPSD	LCO BPSD	HCO BPSD					
A-1	14,000	3.8	447								
A-3	83,900	22.8	2,683								
A-4	20,000	5.4	636								
A-5	250,000	68.0	8,004								
TOTAL	367,900	100.0	11,770	0	0	0	0	0	0	0	0

NOTES: On stream factor = 0.89

TABLE A III - 3

INCREASED PROCESS UNIT CAPACITIES FOR INDIVIDUAL REFINERIES

ATLANTIC REGION, CASE NO. 3

REFINERY CODE	CRUDE CAPACITY BPCD	%	DISTILLATE & GAS OIL HTU				H-OIL BPSD	HYDROGEN PLANT (97%) MMSCFSD	AMINE PLANT MMSCFSD	SULFUR PLANT STPSD	SOUR WATER STRIPPER BPSD
			KERO BPSD	LGO BPSD	LCO BPSD	HCO BPSD					
A-1	14,000	3.8					1,520	1.0			82
A-3	83,900	22.8					9,115	4.0			490
A-4	20,000	5.4					2,159	1.0			116
A-5	250,000	68.0					27,186	11.5			1462
TOTAL	367,900	100.0	0	0	0	0	39,980	17.5	0	0	2150

NOTES: On stream factor = 0.89

TABLE A III - 4

INCREASED PROCESS UNIT CAPACITIES FOR INDIVIDUAL REFINERIES

ATLANTIC REGION, CASE NO. 4

REFINERY CODE	CRUDE CAPACITY BPCD	%	DISTILLATE & GAS OIL HTU				H-OIL BPSD	HYDROGEN PLANT (97%) MMSCFSD	AMINE PLANT MMSCFSD	SULFUR PLANT STPSD	SOUR WATER STRIPPER BPSD
			KERO BPSD	LGO BPSD	LCO BPSD	HCO BPSD					
A-1	14,000	3.8	148				1,520	2.0		1	169
A-3	83,900	22.8	889				9,115	8.5		5	1,012
A-4	20,000	5.4	211				2,159	2.0		2	240
A-5	250,000	68.0	2,652				27,186	24.5		16	3,020
TOTAL	367,900	100.0	3,900	0	0	0	39,980	37.0	0	24	4,441

NOTES: On stream factor = 0.89

TABLE A III - 5

INCREASED PROCESS UNIT CAPACITIES FOR INDIVIDUAL REFINERIES

ATLANTIC REGION, CASE NO. 5

REFINERY CODE	CRUDE CAPACITY BPCD	%	DISTILLATE & GAS OIL HTU				H-OIL BPSD	HYDROGEN PLANT (97%) MMSCFSD	AMINE PLANT MMSCFSD	SULFUR PLANT STPSD	SOUR WATER STRIPPER BPSD
			KERO BPSD	LGO BPSD	LCO BPSD	HCO BPSD					
A-1	14,000	3.8					1,457	1.5		1	73
A-3	83,900	22.8					8,739	6.5		2	441
A-4	20,000	5.4					2,070	2.0		1	104
A-5	250,000	68.0					26,064	19.0		5	1,314
TOTAL	367,900	100.0	0	0	0	0	38,330	29.0	0	9	1,932

NOTES: On stream factor = 0.89

TABLE A III - 6

INCREASED PROCESS UNIT CAPACITIES FOR INDIVIDUAL REFINERIES

ATLANTIC REGION, CASE NO. 6

REFINERY CODE	CRUDE CAPACITY BPCD	%	DISTILLATE & GAS OIL HTU				H-OIL BPSD	HYDROGEN PLANT (97%) MMSCFSD	AMINE PLANT MMSCFSD	SULFUR PLANT STPSD	SOUR WATER STRIPPER BPSD
			KERO BPSD	LGO BPSD	LCO BPSD	HCO BPSD					
A-1	14,000	3.8	82				1,457	2		2	164
A-3	83,900	22.8	490				8,739	11		7	982
A-4	20,000	5.4	116				2,070	3		2	232
A-5	250,000	68.0	1,462				26,064	33		22	2,929
TOTAL	367,900	100.0	2,150	0	0	0	38,330	49	0	33	4,307

NOTES: On stream factor = 0.89

TABLE A III - 7

INCREASED PROCESS UNIT CAPACITIES FOR INDIVIDUAL REFINERIES

QUEBEC REGION, CASE NO. 1

REFINERY CODE	CRUDE CAPACITY BPCD	%	DISTILLATE & GAS OIL HTU				H-OIL BPSD	HYDROGEN PLANT (97%) MMSCFSD	AMINE PLANT MMSCFSD	SULFUR PLANT STPSD	SOUR WATER STRIPPER BPSD
			KERO BPSD	LGO BPSD	LCO BPSD	HCO BPSD					
Q-1	73,000	11.8									
Q-2	100,000	16.2									
Q-3	77,300	12.5									
Q-4	77,600	12.6									
Q-5	95,000	15.4									
Q-6	120,000	19.4									
Q-7	74,500	12.1									
TOTAL	617,400	100.0	0	0	0	0	0	0	0	0	0

NOTES: On stream factor = 0.89

TABLE A III - 8

INCREASED PROCESS UNIT CAPACITIES FOR INDIVIDUAL REFINERIES

QUEBEC REGION, CASE NO. 2

REFINERY CODE	CRUDE CAPACITY BPCD	%	DISTILLATE & GAS OIL HTU				H-OIL BPSD	HYDROGEN PLANT (97%) MMSCFSD	AMINE PLANT MMSCFSD	SULFUR PLANT STPSD	SOUR WATER STRIPPER BPSD
			KERO BPSD	LGO BPSD	LCO BPSD	HCO BPSD					
Q-1	73,000	11.8									263
Q-2	100,000	16.2									361
Q-3	77,300	12.5									279
Q-4	77,600	12.6									281
Q-5	95,000	15.4									343
Q-6	120,000	19.4									432
Q-7	74,500	12.1									270
TOTAL	617,400	100.0	0	0	0	0	0	0	0	0	2,229

NOTES: On stream factor = 0.89

TABLE A III - 9

INCREASED PROCESS UNIT CAPACITIES FOR INDIVIDUAL REFINERIES

QUEBEC REGION, CASE NO. 3

REFINERY CODE	CRUDE CAPACITY (BPCD)	%	DISTILLATE & GAS OIL HTU				H-OIL BPSD	HYDROGEN PLANT (97%) MMSCFSD	AMINE PLANT MMSCFSD	SULFUR PLANT STPSD	SOUR WATER STRIPPER BPSD
			KERO BPSD	LGO BPSD	LCO BPSD	HCO BPSD					
Q-1	73,000	11.8					9,365	0.7		**	1,018
Q-2	100,000	16.2					12,856	1.0		30	1,397
Q-3	77,300	12.5					9,920	0.8		**	1,078
Q-4	77,600	12.6					9,999	0.8		**	1,087
Q-5	95,000	15.4					12,221	0.9		**	1,328
Q-6	120,000	19.4					15,396	1.1		**	1,673
Q-7	74,500	12.1					9,603	0.7		**	1,043
TOTAL	617,400	100.0	0	0	0	0	79,360	6.0	0	180	8,624

NOTES: On stream factor = 0.89

** Centralized sulfur plant for Q-1,Q-3, Q-4, Q-5, Q-6, Q-7, is 150 STPSD

TABLE A III - 10

INCREASED PROCESS UNIT CAPACITIES FOR INDIVIDUAL REFINERIES

QUEBEC REGION, CASE NO. 4

REFINERY CODE	CRUDE CAPACITY BPCD	%	DISTILLATE & GAS OIL HTU				H-OIL BPSD	HYDROGEN PLANT (97%) MMSCFSD	AMINE PLANT MMSCFSD	SULFUR PLANT STPSD	SOUR WATER STRIPPER BPSD
			KERO BPSD	LGO BPSD	LCO BPSD	HCO BPSD					
Q-1	73,000	11.8					9,365	4.7		**	1,475
Q-2	100,000	16.2					12,856	6.5		37	2,025
Q-3	77,300	12.5					9,920	5.0		**	1,562
Q-4	77,600	12.6					9,999	5.0		**	1,575
Q-5	95,000	15.4					12,221	6.2		**	1,925
Q-6	120,000	19.4					15,396	7.8		**	2,425
Q-7	74,500	12.1					9,603	4.8		**	1,512
TOTAL	617,400	100.0	0	0	0	0	79,360	40	0	225	12,500

NOTES: On stream factor = 0.89

** Centralized sulfur plant for Q-1, Q-3, Q-4, Q-5, Q-6, Q-7 is 188 STPSD

TABLE A III - 11

INCREASED PROCESS UNIT CAPACITIES FOR INDIVIDUAL REFINERIES

QUEBEC REGION, CASE NO. 5

REFINERY CODE	CRUDE CAPACITY BPCD	%	DISTILLATE & GAS OIL HTU				H-OIL BPSD	HYDROGEN PLANT (97%) MMSCFSD	AMINE PLANT MMSCFSD	SULFUR PLANT STPSD	SOUR WATER STRIPPER BPSD
			KERO BPSD	LGO BPSD	LCO BPSD	HCO BPSD					
Q-1	73,000	11.8					9,056	4.7		**	1,026
Q-2	100,000	16.2					12.433	6.5		33	1,408
Q-3	77,300	12.5					9,594	5.0		**	1,087
Q-4	77,600	12.6					9,670	5.0		**	1,095
Q-5	95,000	15.4					11,820	6.2		**	1,339
Q-6	120,000	19.4					14,890	7.8		**	1,687
Q-7	74,500	12.1					9,287	4.8		**	1,052
TOTAL	617,400	100.0	0	0	0	0	76,750	40	0	197	8,694

NOTES: On stream factor = 0.89

** Centralized sulfur plant for
Q-1, O-3, Q-4, Q-5, Q-6, Q-7
is 164 STPSD

TABLE A III - 12

INCREASED PROCESS UNIT CAPACITIES FOR INDIVIDUAL REFINERIES

QUEBEC REGION, CASE NO. 6

REFINERY CODE	CRUDE CAPACITY BPCD	%	DISTILLATE & GAS OIL HTU				H-OIL BPSD	HYDROGEN PLANT (97%) MMSCFSD	AMINE PLANT MMSCFSD	SULFUR PLANT STPSD	SOUR WATER STRIPPER BPSD
			KERO BPSD	LGO BPSD	LCO BPSD	HCO BPSD					
Q-1	73,000	11.8					9,056	8.9		**	1,505
Q-2	100,000	16.2					12,433	12.2		40	2,037
Q-3	77,300	12.5					9,594	9.4		**	1,594
Q-4	77,600	12.6					9,670	9.4		**	1,607
Q-5	95,000	15.4					11,820	11.5		**	1,964
Q-6	120,000	19.4					14,890	14.5		**	2,474
Q-7	74,500	12.1					9,287	9.1		**	1,543
TOTAL	617,400	100.0	0	0	0	0	76,750	75	0	242	12,754

NOTES: On stream factor = 0.89

** Centralized sulfur plant for Q-1, Q-3, Q-4, Q-5, Q-6, Q-7 is 202 STPSD

TABLE A III - 13

INCREASED PROCESS UNIT CAPACITIES FOR INDIVIDUAL REFINERIES

ONTARIO REGION, CASE NO. 1

REFINERY CODE	CRUDE CAPACITY BPCD	%	DISTILLATE & GAS OIL HTU				H-OIL BPSD	HYDROGEN PLANT (97%) MMSCFSD	AMINE PLANT MMSCFSD	SULFUR PLANT STPSD	SOUR WATER STRIPPER BPSD
			KERO BPSD	LGO BPSD	LCO BPSD	HCO BPSD					
0-1	80,000	10.6									
0-2	79,100	10.4									
0-3	126,100	16.6									
0-4	170,000	22.4									
0-5	44,000	5.8									
0-6	74,000	9.8									
0-7	90,000	11.9									
0-8	95,000	12.5									
TOTAL	758,200	100.0	0	0	0	0	0	0	0	0	0

NOTES: On stream factor = 0 .89

TABLE A III - 14

INCREASED PROCESS UNIT CAPACITIES FOR INDIVIDUAL REFINERIES

ONTARIO REGION, CASE NO. 2

REFINERY CODE	CRUDE CAPACITY BPCD	%	DISTILLATE & GAS OIL HTU				H-OIL BPSD	HYDROGEN PLANT (97%) MMSCFSD	AMINE PLANT MMSCFSD	SULFUR PLANT STPSD	SOUR WATER STRIPPER BPSD
			KERO BPSD	LGO BPSD	LCO BPSD	HCO BPSD					
0-1	80,000	10.6									106
0-2	79,100	10.4									104
0-3	126,100	16.6									167
0-4	170,000	22.4									225
0-5	44,000	5.8									58
0-6	74,000	9.8									98
0-7	90,000	11.9									120
0-8	95,000	12.5									126
TOTAL	758,200	100.0	0	0	0	0	0	0	0	0	1,004

NOTES: On stream factor = 0.89

TABLE A III - 15

INCREASED PROCESS UNIT CAPACITIES FOR INDIVIDUAL REFINERIES

ONTARIO REGION, CASE NO. 3

REFINERY CODE	CRUDE CAPACITY BPCD	%	DISTILLATE & GAS OIL HTU				H-OIL BPSD	HYDROGEN PLANT (97%) MMSCFSD	AMINE PLANT MMSCFSD	SULFUR PLANT STPSD	SOUR WATER STRIPPER BPSD
			KERO BPSD	LGO BPSD	LCO BPSD	HCO BPSD					
0-1	80,000	10.6					6,942				648
0-2	79,100	10.4					6,811				636
0-3	126,100	16.6					10,872				1,014
0-4	170,000	22.4					14,671				1,369
0-5	44,000	5.8					3,799				355
0-6	74,000	9.8					6,419				599
0-7	90,000	11.9					7,794				727
0-8	95,000	12.5					8,187				764
TOTAL	758,200	100.0	0	0	0	0	65,495	0	0	0	6,112

NOTES: On stream factor = 0.89

TABLE A III - 16

INCREASED PROCESS UNIT CAPACITIES FOR INDIVIDUAL REFINERIES

ONTARIO REGION, CASE NO. 4

REFINERY CODE	CRUDE CAPACITY BPCD	%	DISTILLATE & GAS OIL HTU				H-OIL BPSD	HYDROGEN PLANT (97%) MMSCFSD	AMINE PLANT MMSCFSD	SULFUR PLANT STPSD	SOUR WATER STRIPPER BPSD
			KERO BPSD	LGO BPSD	LCO BPSD	HCO BPSD					
0-1	80,000	10.6					6,942				913
0-2	79,100	10.4					6,811				896
0-3	126,100	16.6					10,872				1,430
0-4	170,000	22.4					14,671				1,930
0-5	44,000	5.8					3,799				500
0-6	74,000	9.8					6,419				844
0-7	90,000	11.9					7,794				1,025
0-8	95,000	12.5					8,187				1,077
TOTAL	758,200	100.0	0	0	0	0	65,495	0	0	0	8,615

NOTES: On stream factor = 0.89

TABLE A III - 17

INCREASED PROCESS UNIT CAPACITIES FOR INDIVIDUAL REFINERIES

ONTARIO REGION, CASE NO. 5

REFINERY CODE	CRUDE CAPACITY BPCD	%	DISTILLATE & GAS OIL HTU				H-OIL BPSD	HYDROGEN PLANT (97%) MMSCFSD	AMINE PLANT MMSCFSD	SULFUR PLANT STPSD	SOUR WATER STRIPPER BPSD
			KERO BPSD	LGO BPSD	LCO BPSD	HCO BPSD					
0-1	80,000	10.6					6,946				704
0-2	79,100	10.4					6,815				690
0-3	126,100	16.6					10,878				1,103
0-4	170,000	22.4					14,679				1,488
0-5	44,000	5.8					3,802				385
0-6	74,000	9.8					6,422				651
0-7	90,000	11.9					7,798				790
0-8	95,000	12.5					8,192				830
TOTAL	758,200	100.0	0	0	0	0	65,532	0	0	0	6,641

NOTES: On stream factor = 0.89

TABLE A III - 18

INCREASED PROCESS UNIT CAPACITIES FOR INDIVIDUAL REFINERIES

ONTARIO REGION, CASE NO. 6

REFINERY CODE	CRUDE CAPACITY BPCD	%	DISTILLATE & GAS OIL HTU				H-OIL BPSD	HYDROGEN PLANT (97%) MMSCFSD	AMINE PLANT MMSCFSD	SULFUR PLANT STPSD	SOUR WATER STRIPPER BPSD
			KERO BPSD	LGO BPSD	LCO BPSD	HCO BPSD					
0-1	80,000	10.6					6,946				1,012
0-2	79,100	10.4					6,815				993
0-3	126,100	16.6					10,878				1,585
0-4	170,000	22.4					14,679				2,139
0-5	44,000	5.8					3,802				554
0-6	74,000	9.8					6,422				936
0-7	90,000	11.9					7,798				1,136
0-8	95,000	12.5					8,192				1,193
TOTAL	758,200	100.0	0	0	0	0	65,532	0	0	0	9,548

NOTES: On stream factor = 0.89

TABLE A III - 19

INCREASED PROCESS UNIT CAPACITIES FOR INDIVIDUAL REFINERIES

WESTERN REGION, CASE NO. 1

REFINERY CODE	CRUDE CAPACITY BPCD	%	DISTILLATE & GAS OIL HTU				H-OIL BPSD	HYDROGEN PLANT (97%) MMSCFSD	AMINE PLANT MMSCFSD	SULFUR PLANT STPSD	SOUR WATER STRIPPER BPSD
			KERO BPSD	LGO BPSD	LCO BPSD	HCO BPSD					
W-1	35,000	6.5								0	
W-2	9,300	1.7								0	
W-3	37,200	7.0								0	
W-4	10,000	1.9								0	
W-5	40,700	7.6								0	
W-6	14,300	2.7								0	
W-7	22,000	4.1								0	
W-8	8,700	1.6								0	
W-9	80,000	15.0								0	
W-10	12,000	2.2								0	
W-11	150,700	28.2								0	
W-12	5,000	0.9								0	
W-13	24,000	4.5								0	
W-14	40,000	7.5								0	
W-15	13,300	2.5								0	
W-16	30,000	5.6								0	
W-17	2,900	0.5								0	
TOTAL	535,100	100.0	0	0	0	0	0	0	0	0	0

NOTES: On stream factor = 0.89

TABLE A III - 20

INCREASED PROCESS UNIT CAPACITIES FOR INDIVIDUAL REFINERIES

WESTERN REGION, CASE NO. 2

REFINERY CODE	CRUDE CAPACITY BPCD	%	DISTILLATE & GAS OIL HTU				H-OIL BPSD	HYDROGEN PLANT (97%) MMSCFSD	AMINE PLANT MMSCFSD	SULFUR PLANT STPSD	SOUR WATER STRIPPER BPSD
			KERO BPSD	LGO BPSD	LCO BPSD	HCO BPSD					
W-1	35,000	6.5									97
W-2	9,300	1.7									25
W-3	37,200	7.0									104
W-4	10,000	1.9									28
W-5	40,700	7.6									113
W-6	14,300	2.7									40
W-7	22,000	4.1									61
W-8	8,700	1.6									24
W-9	80,000	15.0									224
W-10	12,000	2.2									33
W-11	150,700	28.2									420
W-12	5,000	0.9									14
W-13	24,000	4.5									67
W-14	40,000	7.5									112
W-15	13,300	2.5									37
W-16	30,000	5.6									84
W-17	2,900	0.5								-	8
TOTAL	535,100	100.0	0	0	0	0	0	0	0	0	1,491

NOTES: On stream factor = 0.89

TABLE A III - 21

INCREASED PROCESS UNIT CAPACITIES FOR INDIVIDUAL REFINERIES

WESTERN REGION, CASE NO. 3

REFINERY CODE	CRUDE CAPACITY BPCD	%	DISTILLATE & GAS OIL HTU				H-OIL BPSD	HYDROGEN PLANT (97%) MMSCFSD	AMINE PLANT MMSCFSD	SULFUR PLANT STPSD	SOUR WATER STRIPPER BPSD
			KERO BPSD	LGO BPSD	LCO BPSD	HCO BPSD					
W-1	35,000	6.5					4,355			5.5	468
W-2	9,300	1.7					1,140			1.5	123
W-3	37,200	7.0					4,690			5.5	504
W-4	10,000	1.9					1,270			1.5	137
W-5	40,700	7.6					5,090			6.0	547
W-6	14,300	2.7					1,810			2.0	194
W-7	22,000	4.1					2,750			3.5	295
W-8	8,700	1.6					1,070			1.5	115
W-9	80,000	15.0					10,050			12.0	1,080
W-10	12,000	2.2					1,470			2.0	159
W-11	150,700	28.2					18,890			23.0	2,030
W-12	5,000	0.9					600			1.0	65
W-13	24,000	4.5					3,015			3.5	324
W-14	40,000	7.5					5,025			6.0	540
W-15	13,300	2.5					1,675			2.0	180
W-16	30,000	5.6					3,750			4.5	403
W-17	2,900	0.5					350			1.0	36
TOTAL	535,100	100.0	0	0	0	0	67,000	0	0	82	7,200

NOTES: On stream factor = 0.89

TABLE A III - 22

INCREASED PROCESS UNIT CAPACITIES FOR INDIVIDUAL REFINERIES

WESTERN REGION, CASE NO. 4

REFINERY CODE	CRUDE CAPACITY BPCD	%	DISTILLATE & GAS OIL HTU				H-OIL BPSD	HYDROGEN PLANT (97%) MMSCFSD	AMINE PLANT MMSCFSD	SULFUR PLANT STPSD	SOUR WATER STRIPPER BPSD
			KERO BPSD	LGO BPSD	LCO BPSD	HCO BPSD					
W-1	35,000	6.5					4,355			6.5	552
W-2	9,300	1.7					1,140			2.0	145
W-3	37,200	7.0					4,690			7.0	595
W-4	10,000	1.9					1,270			2.0	161
W-5	40,700	7.6					5,090			8.0	646
W-6	14,300	2.7					1,810			3.0	229
W-7	22,000	4.1					2,750			4.0	348
W-8	8,700	1.6					1,070			2.0	136
W-9	80,000	15.0					10,050			15.0	1,274
W-10	12,000	2.2					1,470			2.5	187
W-11	150,700	28.2					18,890			29.0	2,396
W-12	5,000	0.9					600			1.0	76
W-13	24,000	4.5					3,015			4.5	382
W-14	40,000	7.5					5,025			8.0	637
W-15	13,300	2.5					1,675			2.5	212
W-16	30,000	5.6					3,750			6.0	476
W-17	2,900	0.5					350			1.0	43
TOTAL	535,100	100.0	0	0	0	0	67,000	0	0	104	8,495

NOTES: On stream factor = 0.89

TABLE A III - 23

INCREASED PROCESS UNIT CAPACITIES FOR INDIVIDUAL REFINERIES

WESTERN REGION, CASE NO. 5

REFINERY CODE	CRUDE CAPACITY BPCD	%	DISTILLATE & GAS OIL HTU				H-OIL BPSD	HYDROGEN PLANT (97%) MMSCFSD	AMINE PLANT MMSCFSD	SULFUR PLANT STPSD	SOUR WATER STRIPPER BPSD
			KERO BPSD	LGO BPSD	LCO BPSD	HCO BPSD					
W-1	35,000	6.5					4,070			6.0	436
W-2	9,300	1.7					1,065			1.5	114
W-3	37,200	7.0					4,380			6.5	470
W-4	10,000	1.9					1,190			2.0	127
W-5	40,700	7.6					4,755			7.0	510
W-6	14,300	2.7					1,690			2.5	181
W-7	22,000	4.1					2,570			4.0	275
W-8	8,700	1.6					1,000			1.5	107
W-9	80,000	15.0					9,390			14.0	1,006
W-10	12,000	2.2					1,375			2.0	148
W-11	150,700	28.2					17,650			26.5	1,892
W-12	5,000	0.9					565			1.0	60
W-13	24,000	4.5					2,820			4.0	302
W-14	40,000	7.5					4,695			7.0	503
W-15	13,300	2.5					1,565			2.5	168
W-16	30,000	5.6					3,505			5.0	376
W-17	2,900	0.5					315			1.0	34
TOTAL	535,100	100.0	0	0	0	0	62,600	0	0	94	6,709

NOTES: On stream factor = 0.89

TABLE A III - 24

INCREASED PROCESS UNIT CAPACITIES FOR INDIVIDUAL REFINERIES

WESTERN REGION, CASE NO. 6

REFINERY CODE	CRUDE CAPACITY BPCD	%	DISTILLATE & GAS OIL HTU				H-OIL BPSD	HYDROGEN PLANT (97%) MMSCFSD	AMINE PLANT MMSCFSD	SULFUR PLANT STPSD	SOUR WATER STRIPPER BPSD
			KERO BPSD	LGO BPSD	LCO BPSD	HCO BPSD					
W-1	35,000	6.5					4,070			7.5	534
W-2	9,300	1.7					1,065			2.0	140
W-3	37,200	7.0					4,380			8.0	575
W-4	10,000	1.9					1,190			2.0	156
W-5	40,700	7.6					4,755			8.5	624
W-6	14,300	2.7					1,690			3.0	222
W-7	22,000	4.1					2,570			4.5	337
W-8	8,700	1.6					1,000			2.0	131
W-9	80,000	15.0					9,390			17.0	1,231
W-10	12,000	2.2					1,375			2.5	181
W-11	150,700	28.2					17,650			32.0	2,315
W-12	5,000	0.9					565			1.0	74
W-13	24,000	4.5					2,820			5.0	369
W-14	40,000	7.5					4,695			8.5	616
W-15	13,300	2.5					1,565			3.0	205
W-16	30,000	5.6					3,505			6.5	460
W-17	2,900	0.5					315			1.0	41
TOTAL	535,100	100.0	0	0	0	0	62,600	0	0	114	8,211

NOTES: On stream factor = 0 .89

APPENDIX IV

Estimates of Additional Investment Requirements for Individual Refineries

For Four Regions with six cases per region

TABLE A IV-1

ADDITIONAL COST REQUIREMENTS FOR REFINERIES

ATLANTIC REGION CASE 1

COST MM$ / REFINERY CODE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
A-1	0			0	0	0	0
A-3	0			0	0	0	0
A-4	0			0	0	0	0
A-5	0			0	0	0	0
TOTAL	0	-	-	0	0	0	0

NOTES: Regional cost conversion factor using Ontario as base reference: 1.033

TABLE A IV-2

ADDITIONAL COST REQUIREMENTS FOR REFINERIES

ATLANTIC REGION CASE 2

COST MMS / REFINERY CODE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
A-1	6.71*			0	0	0	0
A-3	8.26			0	0	0	0
A-4	6.71*			0	0	0	0
A-5	17.04			0	0	0	0
				0	0	0	0
	*minimum						
	cost for Small						
	Plant						
TOTAL	38.72	-	-	0	0	0	0

NOTES: Regional cost conversion factor using Ontario as base reference: 1.033

TABLE A IV-3

ADDITIONAL COST REQUIREMENTS FOR REFINERIES

ATLANTIC REGION CASE 3

COST MM$ / REFINERY CODE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
A-1	0	-	12.79	12.40*	0	0	0.21
A-3	0	-	50.75	12.91	0	0	0.60
A-4	0	-	16.10	12.40*	0	0	0.23
A-5	0	-	138.59	21.69	0	0	1.22
				*minimum			
				cost for			
				small plant			
TOTAL	0	-	218.23	59.40	0	0	2.26

NOTES: Regional cost conversion factor using Ontario as base reference: 1.033

TABLE A IV-4

ADDITIONAL COST REQUIREMENTS FOR REFINERIES

ATLANTIC REGION CASE 4

COST MM$ / REFINERY CODE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
A-1	6.71*	-	12.79	12.40	0	1.03	0.29
A-3	6.71*	-	50.75	18.08	0	1.55	0.97
A-4	6.71*	-	16.10	12.40	0	1.05	0.37
A-5	8.26	-	138.59	39.25	0	2.58	1.97
	* minimum						
	cost for						
	small plants						
TOTAL	28.39	-	218.23	82.13	0	6.21	3.60

NOTES: Regional cost conversion factor using Ontario as base reference: 1.033

TABLE A IV-5

ADDITIONAL COST REQUIREMENTS FOR REFINERIES

ATLANTIC REGION CASE 5

COST MM$ / REFINERY CODE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
A-1	0	13.92	-	12.40*	0	1.03	0.21
A-3	0	54.15	-	15.50	0	1.05	0.56
A-4	0	17.68	-	12.40	0	1.03	0.21
A-5	0	152.49	-	26.86	0	1.55	1.16
				* minimum			
				cost for small			
				plant			
TOTAL	0	238.24	-	67.16	0	4.66	2.14

NOTES: Regional cost conversion factor using Ontario as base reference: 1.033

TABLE A IV-6

ADDITIONAL COST REQUIREMENTS FOR REFINERIES

ATLANTIC REGION CASE 6

COST MMS / REFINERY CODE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
A-1	6.71*	13.92	-	12.40	0	1.05	0.29
A-3	6.71	54.15	-	21.69	0	1.86	0.94
A-4	6.71	17.68	-	13.43	0	1.05	0.36
A-5	6.71	152.49	-	4649	0	2.58	1.93
	*minimum						
	cost for small						
	plants						
TOTAL	26.84	238.24	-	94.01	0	6.54	3.52

NOTES: Regional cost conversion factor using Ontario as base reference: 1.033

TABLE A IV-7

ADDITIONAL COST REQUIREMENTS FOR REFINERIES

QUEBEC REGION CASE 1

COST MM$ / REFINERY CODE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
Q-1	0			0	0	0	0
Q-2	↓			↓	↓	↓	↓
Q-3	↓			↓	↓	↓	↓
Q-4	↓			↓	↓	↓	↓
Q-5	↓			↓	↓	↓	↓
Q-6	↓			↓	↓	↓	↓
Q-7	↓			↓	↓	↓	↓
TOTAL	0	-	-	0	0	0	0

TABLE A IV-8

ADDITIONAL COST REQUIREMENTS FOR REFINERIES

QUEBEC REGION CASE 2

COST MM$ / REFINERY CODE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
Q-1	0			0	0	0	0.38
Q-2							0.48
Q-3							0.39
Q-4							0.39
Q-5							0.47
Q-6							0.54
Q-7	↓			↓	↓	↓	0.39
TOTAL	0	-	-	0	0	0	3.04

NOTES: Regional cost conversion factor using Ontario as base reference: 1.013

TABLE A IV-9

ADDITIONAL COST REQUIREMENTS FOR REFINERIES

QUEBEC REGION CASE 3

COST MMS / REFINERY CODE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
Q-1	0	-	49.76	12.15	0	*	0.95
Q-2	0	-	65.08	12.15	0	2.63	1.17
Q-3	0	-	52.64	12.15	0	*	0.98
Q-4	0	-	53.11	12.15	0	*	0.98
Q-5	0	-	61.25	12.15	0	* 14.59	1.13
Q-6	0	-	75.60	12.15	0	*	1.30
Q-7	0	-	50.80	12.15	0	*	0.97
				↑			
				MIN. COST for PLANT LESS THAN 2MM SCFD			
TOTAL	0	-	408.24	85.05	0	17.22	7.48

NOTES: Regional cost conversion factor using Ontario as base reference: 1.013

* denotes central Sulfur Plant.

TABLE A IV-10

ADDITIONAL COST REQUIREMENTS FOR REFINERIES

QUEBEC REGION CASE 4

COST MM$ / REFINERY CODE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
Q-1	0	-	49.76	13.17	0	*	1.20
Q-2	0	-	65.08	15.20	0	2.84	1.50
Q-3	0	-	52.64	14.18	0	* 17.02	1.27
Q-4	0	-	53.11	14.18	0	*	1.28
Q-5	0	-	61.25	14.95	0	*	1.45
Q-6	0	-	75.60	17.22	0	*	1.70
Q-7	0	-	50.80	13.50	0	*	1.24
TOTAL	0	-	408.24	102.40	0	19.86	9.64

NOTES: Regional cost conversion factor using Ontario as base reference: 1.013

* denotes central Sulfur Plant.

TABLE A IV-11

ADDITIONAL COST REQUIREMENTS FOR REFINERIES

QUEBEC REGION CASE 5

COST MM$ / REFINERY CODE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
Q-1	0	55.28	-	13.17	0	*	0.95
Q-2	0	72.75	-	15.20	0	2.71	1.18
Q-3	0	58.24	-	14.18	0	*	0.99
Q-4	0	58.64	-	14.18	0	*	1.00
Q-5	0	69.38	-	14.95	0	* 15.40	1.13
Q-6	0	83.47	-	17.22	0	*	1.31
Q-7	0	56.55	-	13.50	0	*	0.97
TOTAL	0	454.31	-	102.40	0	18.11	7.53

NOTES: Regional cost conversion factor using Ontario as base reference: 1.013

* denotes central Sulfur Plant.

TABLE A IV-12

ADDITIONAL COST REQUIREMENTS FOR REFINERIES

QUEBEC REGION CASE 6

COST MM$ / REFINERY CODE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
Q-1	0	55.28	-	18.23	0	*	1.24
Q-2	0	72.75	-	22.29	0	2.89	1.51
Q-3	0	58.24	-	19.25	0	*	1.28
Q-4	0	58.64	-	19.25	0	*	1.28
Q-5	0	69.38	-	21.27	0	* 17.73	1.47
Q-6	0	83.47	-	26.34	0	*	1.71
Q-7	0	56.55	-	18.64	0	*	1.25
TOTAL	0	454.31	-	145.27	0	20.62	9.74

NOTES: Regional cost conversion factor using Ontario as base reference: 1.013

* denotes central Sulfur Plant.

TABLE A IV-13

ADDITIONAL COST REQUIREMENTS FOR REFINERIES

ONTARIO REGION **CASE 1**

COST MM$ / REFINERY CODE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	68%				
O-1	0			0	0	0	0
O-2	│			│	│	│	│
O-3	│			│	│	│	│
O-4	│			│	│	│	│
O-5	│			│	│	│	│
O-6	│			│	│	│	│
O-7	│			│	│	│	│
O-8	│			│	│	│	│
TOTAL	0	-	-	0	0	0	0

NOTES: Regional cost conversion factor using Ontario as the base reference: 1.0

TABLE A IV-14

ADDITIONAL COST REQUIREMENTS FOR REFINERIES

ONTARIO REGION CASE 2

COST MM$ / REFINERY CODE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
0-1	0			0	0	0	0.20
0-2							0.20
0-3							0.28
0-4							0.34
0-5							0.20
0-6							0.20
0-7							0.23
0-8							0.23
TOTAL	0	-	-	0	0	0	1.88

NOTES: Regional cost conversion factor using Ontario as the base reference: 1.0

TABLE A IV-15

ADDITIONAL COST REQUIREMENTS FOR REFINERIES

ONTARIO REGION CASE 3

COST MM$ / REFINERY CODE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	60%				
0-1	0	-	36.70	0	0	0	0.70
0-2		-	35.80				0.69
0-3		-	52.80				0.94
0-4		-	68.02				1.14
0-5		-	22.38				0.46
0-6		-	34.01				0.66
0-7		-	40.28				0.75
0-8	↓	-	42.07	↓	↓	↓	0.78
TOTAL	0	-	332.06	0	0	0	6.12

NOTES: Regional cost conversion factor using Ontario as the base reference: 1.0

TABLE A IV-16

ADDITIONAL COST REQUIREMENTS FOR REFINERIES

ONTARIO REGION CASE 4

COST MM$ / REFINERY CODE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
0-1	0	-	36.70	0	0	0	0.87
0-2	│	-	35.80	│	│	│	0.87
0-3	│	-	52.80	│	│	│	1.18
0-4	│	-	68.02	│	│	│	1.44
0-5	│	-	22.38	│	│	│	0.58
0-6	│	-	34.01	│	│	│	0.82
0-7	│	-	40.28	│	│	│	0.95
0-8	▼	-	42.07	▼	▼	▼	0.97
TOTAL	0	-	332.06	0	0	0	7.68

NOTES: Regional cost conversion factor using Ontario as the base reference: 1.0

TABLE A IV-17

ADDITIONAL COST REQUIREMENTS FOR REFINERIES

ONTARIO REGION **CASE** 5

COST MM$ / REFINERY CODE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
0-1	0	41.02	-	0	0	0	0.74
0-2	↓	40.02	-	↓	↓	↓	0.73
0-3	↓	59.02	-	↓	↓	↓	0.99
0-4	↓	76.02	-	↓	↓	↓	1.19
0-5	↓	25.02	-	↓	↓	↓	0.49
0-6	↓	38.02	-	↓	↓	↓	0.70
0-7	↓	45.02	-	↓	↓	↓	0.79
0-8	↓	47.02	-	↓	↓	↓	0.82
TOTAL	0	371.16	-	0	0	0	6.45

NOTES: Regional cost conversion factor using Ontario as the base reference: 1.0

TABLE A IV-18

ADDITIONAL COST REQUIREMENTS FOR REFINERIES

ONTARIO REGION CASE 6

COST MM$ / REFINERY CODE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
0-1	0	41.02	-	0	0	0	0.95
0-2	|	40.02	-	|	|	|	0.92
0-3	|	59.02	-	|	|	|	1.26
0-4	|	76.02	-	|	|	|	1.54
0-5	|	25.02	-	|	|	|	0.62
0-6	|	38.02	-	|	|	|	0.88
0-7	|	45.02	-	|	|	|	1.00
0-8	↓	47.02	-	↓	↓	↓	1.04
TOTAL	0	371.16	-	0	0	0	8.21

NOTES: Regional cost conversion factor using Ontario as the base reference: 1.0

TABLE A IV-19

ADDITIONAL COST REQUIREMENTS FOR REFINERIES

WESTERN REGION CASE 1

COST MM$ / REFINERY CODE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
W-1	0			0	0	0	0
W-2							
W-3							
W-4							
W-5							
W-6							
W-7							
W-8							
W-9							
W-10							
W-11							
W-12							
W-13							
W-14							
W-15							
W-16							
W-17	↓			↓	↓	↓	↓
TOTAL	0			0	0	0	0

NOTES:

Regional cost conversion factor using Ontario as base reference:

W1 - W7	1.091
W8 - W17	1.024

TABLE A IV-20

ADDITIONAL COST REQUIREMENTS FOR REFINERIES

WESTERN REGION CASE 2

COST MMS / REFINERY CODE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
W-1	0			0	0	0	0.22
W-2							0.22
W-3							0.22
W-4							0.22
W-5							0.23
W-6							0.22
W-7							0.22
W-8							0.20
W-9							0.35
W-10							0.20
W-11							0.53
W-12							0.20
W-13							0.20
W-14							0.20
W-15							0.20
W-16							0.20
W-17	▼			▼	▼	▼	0.20
TOTAL	0			0	0	0	4.03

NOTES:

Regional cost conversion factor using Ontario as base reference:

W1 - W7	1.091
W8 - W17	1.024

TABLE A IV-21

ADDITIONAL COST REQUIREMENTS FOR REFINERIES

WESTERN REGION CASE 3

COST MM$ / REFINERY CODE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
W-1	0	-	27.33	0	0	1.75	0.61
W-2		-	10.74			1.09	0.25
W-3		-	29.27			1.75	0.64
W-4		-	11.61			1.09	0.27
W-5		-	31.51			1.83	0.68
W-6		-	14.15			1.11	0.34
W-7		-	19.52			1.37	0.45
W-8		-	9.91			1.02	0.23
W-9		-	50.44			2.37	0.99
W-10		-	11.92			1.04	0.28
W-11		-	96.29			2.56	1.52
W-12		-	6.88			1.02	0.20
W-13		-	19.44			1.29	0.44
W-14		-	14.26			1.70	0.63
W-15		-	12.66			1.04	0.30
W-16		-	22.93			1.46	0.52
W-17	↓	-	4.95	↓	↓	1.02	0.20
TOTAL	0	-	393.81	0	0	24.51	8.55

NOTES:

Regional cost conversion factor using Ontario as base reference:

W1 - W7	1.091
W8 - W17	1.024

TABLE A IV-22

ADDITIONAL COST REQUIREMENTS FOR REFINERIES

WESTERN REGION CASE 4

COST MM$ / REFINERY CODE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
W-1	0	-	27.33	0	0	1.88	0.68
W-2		-	10.74			1.11	0.28
W-3		-	29.27			1.96	0.71
W-4		-	11.61			1.11	0.30
W-5		-	31.51			2.11	0.75
W-6		-	14.15			1.29	0.37
W-7		-	19.52			1.47	0.50
W-8		-	3.91			1.04	0.25
W-9		-	50.44			2.44	1.13
W-10		-	11.92			1.13	0.31
W-11		-	96.29			2.66	1.69
W-12		-	6.88			1.02	0.20
W-13		-	19.44			1.46	0.49
W-14		-	14.26			1.97	0.70
W-15		-	12.66			1.13	0.33
W-16		-	22.93			1.70	0.58
W-17	▼	-	4.95	▼	▼	1.02	0.20
TOTAL	0	-	393.81	0	0	26.50	9.47

NOTES:

Regional cost conversion factor using
Ontario as base reference:

W1 - W7	1.091
W8 - W17	1.024

TABLE A IV-23

ADDITIONAL COST REQUIREMENTS FOR REFINERIES

WESTERN REGION CASE 5

COST MM$ / REFINERY CODE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
W-1	0	28.53	-	0	0	1.83	0.58
W-2		11.45	-			1.09	0.24
W-3		30.45	-			1.91	0.61
W-4		12.22	-			1.11	0.26
W-5		32.78	-			1.96	0.64
W-6		15.06	-			1.20	0.32
W-7		20.35	-			1.47	0.43
W-8		10.24	-			1.02	0.22
W-9		52.52	-			2.41	0.96
W-10		12.49	-			1.04	0.27
W-11		92.26	-			2.61	1.43
W-12		7.27	-			1.02	0.20
W-13		20.69	-			1.38	0.42
W-14		13.82	-			1.84	0.60
W-15		13.62	-			1.13	0.29
W-16		24.57	-			1.54	0.49
W-17		5.12	-			1.02	0.20
TOTAL	0	403.44	-	0	0	25.58	8.16

NOTES:

Regional cost conversion factor using Ontario as base reference:

W1 - W7	1.091
W8 - W17	1.024

TABLE A IV-24

ADDITIONAL COST REQUIREMENTS FOR REFINERIES

WESTERN REGION CASE 6

COST MM$ / REFINERY CODE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
W-1	0	28.53	-	0	0	2.01	0.67
W-2		11.45	-			1.11	0.27
W-3		30.45	-			2.11	0.70
W-4		12.22	-			1.11	0.29
W-5		32.78	-			2.18	0.74
W-6		15.06	-			1.29	0.37
W-7		20.35	-			1.56	0.49
W-8		10.24	-			1.04	0.25
W-9		52.52	-			2.46	1.11
W-10		12.49	-			1.13	0.30
W-11		92.26	-			2.71	1.64
W-12		7.27	-			1.02	0.20
W-13		20.69	-			1.54	0.49
W-14		13.82	-			2.05	0.69
W-15		13.62	-			1.21	0.33
W-16		24.57	-			1.79	0.56
W-17	↓	5.12	-	↓	↓	1.02	0.20
TOTAL	0	403.44	-	0	0	27.34	9.30

NOTES:

Regional cost conversion factor using
Ontario as base reference:

W1 - W7	1.091
W8 - W17	1.024

APPENDIX V

Estimates of Additional Manpower Requirements for Individual Refineries For Four Regions with six cases per region

TABLE A V-1

ADDITIONAL MANPOWER REQUIREMENTS FOR REFINERIES

ATLANTIC REGION CASE 1

MANPOWER (PERSONS) / REFINERY CASE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
A-1	0	0	0	0	0	0	0
A-3	0	0	0	0	0	0	0
A-4	0	0	0	0	0	0	0
A-5	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	0

TABLE A V-2

ADDITIONAL MANPOWER REQUIREMENTS FOR REFINERIES

ATLANTIC REGION CASE 2

MANPOWER (PERSONS) / REFINERY CASE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
A-1	9	0	0	0	0	0	0
A-3	9	↓	↓	↓	↓	↓	↓
A-4	9	↓	↓	↓	↓	↓	↓
A-5	9	↓	↓	↓	↓	↓	↓
TOTAL	36	0	0	0	0	0	0

TABLE A V-3

ADDITIONAL MANPOWER REQUIREMENTS FOR REFINERIES

ATLANTIC REGION CASE 3

MANPOWER (PERSONS) / REFINERY CASE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
A-1	0	-	13	9	0	0	2.5
A-3	↓	-	13	9	↓	↓	2.5
A-4	↓	-	13	9	↓	↓	2.5
A-5	↓	-	13	9	↓	↓	2.5
TOTAL	0	0	52	36	0	0	10

TABLE A V-4

ADDITIONAL MANPOWER REQUIREMENTS FOR REFINERIES

ATLANTIC REGION CASE 4

MANPOWER (PERSONS) / REFINERY CASE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
A-1	9	-	13	9	0	9	2.5
A-3	9	-	13	9	0	9	2.5
A-4	9	-	13	9	0	9	2.5
A-5	9	-	13	9	0	9	2.5
TOTAL	36	-	52	36	0	36	10

TABLE A V-5

ADDITIONAL MANPOWER REQUIREMENTS FOR REFINERIES

ATLANTIC REGION CASE 5

MANPOWER (PERSONS) / REFINERY CASE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	68%				
A-1	0	13	-	9	0	9	2.5
A-3	0	13	-	9	0	9	2.5
A-4	0	13	-	9	0	9	2.5
A-5	0	13	-	9	0	9	2.5
TOTAL	0	52	-	36	0	36	10

TABLE 3 V-6

ADDITIONAL MANPOWER REQUIREMENTS FOR REFINERIES

ATLANTIC REGION CASE 6

MANPOWER (PERSONS) / REFINERY CASE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
A-1	9	13	-	0	0	9	2.5
A-3	9	13	-	0	0	9	2.5
A-4	9	13	-	0	0	9	2.5
A-5	9	13	-	0	0	9	2.5
TOTAL	36	52	-	0	0	36	10

TABLE A V-7

ADDITIONAL MANPOWER REQUIREMENTS FOR REFINERIES

QUEBEC REGION CASE 1

MANPOWER (PERSONS) / REFINERY CASE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	60%				
Q-1	0	0	0	0	0	0	0
Q-2	↓	↓	↓	↓	↓	↓	↓
Q-3	↓	↓	↓	↓	↓	↓	↓
Q-4	↓	↓	↓	↓	↓	↓	↓
Q-5	↓	↓	↓	↓	↓	↓	↓
Q-6	↓	↓	↓	↓	↓	↓	↓
Q-7	↓	↓	↓	↓	↓	↓	↓
TOTAL	0	0	0	0	0	0	0

TABLE [illegible]

ADDITIONAL MANPOWER REQUIREMENTS FOR REFINERIES

QUEBEC REGION CASE 2

MANPOWER (PERSONS) / REFINERY CASE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	60%				
Q-1	0	0	0	0	0	0	2.5
Q-2							2.5
Q-3							2.5
Q-4							2.5
Q-5							2.5
Q-6							2.5
Q-7	▼	▼	▼	▼	▼	▼	2.5
TOTAL	0	0	0	0	0	0	17.5

TABLE A V-9

ADDITIONAL MANPOWER REQUIREMENTS FOR REFINERIES

QUEBEC REGION　　　　CASE 3

MANPOWER (PERSONS) / REFINERY CASE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
Q-1	0	-	13	9	0	*	2.5
Q-2		-	13	9		9	2.5
Q-3		-	13	9		*	2.5
Q-4		-	13	9		*	2.5
Q-5		-	13	9		* 9	2.5
Q-6		-	13	9		*	2.5
Q-7	↓	-	13	9	↓	*	2.5
						* CENTRAL	
						SULFUR	
						PLANT	
TOTAL	0	-	91	63	0	18	17.5

TABLE A V-10

ADDITIONAL MANPOWER REQUIREMENTS FOR REFINERIES

QUEBEC REGION CASE 4

MANPOWER (PERSONS) / REFINERY CASE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
Q-1	0	-	13	9	0	*	2.5
Q-2		-	13	9		9	2.5
Q-3		-	13	9		*	2.5
Q-4		-	13	9		* 9	2.5
Q-5		-	13	9		*	2.5
Q-6		-	13	9		*	2.5
Q-7	↓	-	13	9	↓	*	2.5
						*CENTRAL	
						SULFUR PLANT	
TOTAL	0	-	91	63	0	18	17.5

TABLE A V-11

ADDITIONAL MANPOWER REQUIREMENTS FOR REFINERIES

QUEBEC REGION CASE 5

MANPOWER (PERSONS) / REFINERY CASE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
Q-1	0	13	–	9	0	*	2.5
Q-2	↓	13	–	9	↓	9	2.5
Q-3	↓	13	–	9	↓	*	2.5
Q-4	↓	13	–	9	↓	* } 9	2.5
Q-5	↓	13	–	9	↓	*	2.5
Q-6	↓	13	–	9	↓	*	2.5
Q-7	↓	13	-	9	↓	*	2.5
						* CENTRAL	
						SULFUR	
						PLANT	
TOTAL	0	91	–	63	0	18	17.5

TABLE A V-12

ADDITIONAL MANPOWER REQUIREMENTS FOR REFINERIES

QUEBEC REGION CASE 6

MANPOWER (PERSONS) / REFINERY CASE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
Q-1	0	13	-	9	0	*	2.5
Q-2		13	-	9		9	2.5
Q-3		13	-	9		* 9	2.5
Q-4		13	-	9		*	2.5
Q-5		13	-	9		*	2.5
Q-6		13	-	9		*	2.5
Q-7		13	-	9		*	2.5
TOTAL	0	91	-	63	0	18	17.5

TABLE A V-13

ADDITIONAL MANPOWER REQUIREMENTS FOR REFINERIES

ONTARIO REGION CASE 1

MANPOWER (PERSONS) / REFINERY CASE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
0-1	0	0	0	0	0	0	0
0-2	↓	↓	↓	↓	↓	↓	↓
0-3	↓	↓	↓	↓	↓	↓	↓
0-4	↓	↓	↓	↓	↓	↓	↓
0-5	↓	↓	↓	↓	↓	↓	↓
0-6	↓	↓	↓	↓	↓	↓	↓
0-7	↓	↓	↓	↓	↓	↓	↓
0-8	↓	↓	↓	↓	↓	↓	↓
TOTAL	0	0	0	0	0	0	0

TABLE A V-14

ADDITIONAL MANPOWER REQUIREMENTS FOR REFINERIES

ONTARIO REGION CASE 2

MANPOWER (PERSONS) / REFINERY CASE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
0-1	0	0	0	0	0	0	2.5
0-2	↓	↓	↓	↓	↓	↓	2.5
0-3	↓	↓	↓	↓	↓	↓	2.5
0-4	↓	↓	↓	↓	↓	↓	2.5
0-5	↓	↓	↓	↓	↓	↓	2.5
0-6	↓	↓	↓	↓	↓	↓	2.5
0-7	↓	↓	↓	↓	↓	↓	2.5
0-8	↓	↓	↓	↓	↓	↓	2.5
TOTAL	0	0	0	0	0	0	20

TABLE A V-15

ADDITIONAL MANPOWER REQUIREMENTS FOR REFINERIES

ONTARIO REGION CASE 3

MANPOWER (PERSONS) / REFINERY CASE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
0-1	0	-	13	0	0	0	2.5
0-2	↓	-	13	↓	↓	↓	2.5
0-3	↓	-	13	↓	↓	↓	2.5
0-4	↓	-	13	↓	↓	↓	2.5
0-5	↓	-	13	↓	↓	↓	2.5
0-6	↓	-	13	↓	↓	↓	2.5
0-7	↓	-	13	↓	↓	↓	2.5
0-8	↓	-	13	↓	↓	↓	2.5
TOTAL	0	-	104	0	0	0	20

TABLE A V-16

ADDITIONAL MANPOWER REQUIREMENTS FOR REFINERIES

ONTARIO REGION CASE 4

MANPOWER (PERSONS) / REFINERY CASE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
0-1	0	-	13	0	0	0	2.5
0-2	↓	-	↓	↓	↓	↓	↓
0-3	↓	-	↓	↓	↓	↓	↓
0-4	↓	-	↓	↓	↓	↓	↓
0-5	↓	-	↓	↓	↓	↓	↓
0-6	↓	-	↓	↓	↓	↓	↓
0-7	↓	-	↓	↓	↓	↓	↓
0-8	↓	-	↓	↓	↓	↓	↓
TOTAL	0	-	104	0	0	0	20

TABLE A V-17

ADDITIONAL MANPOWER REQUIREMENTS FOR REFINERIES

ONTARIO REGION CASE 5

MANPOWER (PERSONS) / REFINERY CASE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
0-1	0	13	-	0	0	0	2.5
0-2			-				
0-3			-				
0-4			-				
0-5			-				
0-6			-				
0-7			-				
0-8	↓	↓	-	↓	↓	↓	↓
TOTAL	0	104	-	0	0	0	20

TABLE A V-18

ADDITIONAL MANPOWER REQUIREMENTS FOR REFINERIES

ONTARIO REGION CASE 6

MANPOWER (PERSONS) / REFINERY CASE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
O-1	0	13	-	0	0	0	2.5
O-2			-				
O-3			-				
O-4			-				
O-5			-				
O-6			-				
O-7			-				
O-8	↓	↓	-	↓	↓	↓	↓
TOTAL	0	104	-	0	0	0	20

TABLE A V-19

ADDITIONAL MANPOWER REQUIREMENTS FOR REFINERIES

WESTERN REGION CASE 1

MANPOWER (PERSONS) / REFINERY CASE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
W-1	0	0	0	0	0	0	0
W-2							
W-3							
W-4							
W-5							
W-6							
W-7							
W-8							
W-9							
W-10							
W-11							
W-12							
W-13							
W-14							
W-15							
W-16							
W-17	↓	↓	↓	↓	↓	↓	↓
TOTAL	0	0	0	0	0	0	0

TABLE A V-20

ADDITIONAL MANPOWER REQUIREMENTS FOR REFINERIES

WESTERN REGION. CASE 2

MANPOWER (PERSONS) / REFINERY CASE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
W-1	0	0	0	0	0	0	2.5
W-2	↓	↓	↓	↓	↓	↓	↓
W-3	↓	↓	↓	↓	↓	↓	↓
W-4	↓	↓	↓	↓	↓	↓	↓
W-5	↓	↓	↓	↓	↓	↓	↓
W-6	↓	↓	↓	↓	↓	↓	↓
W-7	↓	↓	↓	↓	↓	↓	↓
W-8	↓	↓	↓	↓	↓	↓	↓
W-9	↓	↓	↓	↓	↓	↓	↓
W-10	↓	↓	↓	↓	↓	↓	↓
W-11	↓	↓	↓	↓	↓	↓	↓
W-12	↓	↓	↓	↓	↓	↓	↓
W-13	↓	↓	↓	↓	↓	↓	↓
W-14	↓	↓	↓	↓	↓	↓	↓
W-15	↓	↓	↓	↓	↓	↓	↓
W-16	↓	↓	↓	↓	↓	↓	↓
W-17	↓	↓	↓	↓	↓	↓	↓
TOTAL	0	0	0	0	0	0	45

TABLE A V-21

ADDITIONAL MANPOWER REQUIREMENTS FOR REFINERIES

WESTERN REGION CASE 3

MANPOWER (PERSONS) / REFINERY CASE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
W-1	0	-	13	0	0	9	2.5
W-2	↓	↓	↓	↓	↓	↓	↓
W-3	↓	↓	↓	↓	↓	↓	↓
W-4	↓	↓	↓	↓	↓	↓	↓
W-5	↓	↓	↓	↓	↓	↓	↓
W-6	↓	↓	↓	↓	↓	↓	↓
W-7	↓	↓	↓	↓	↓	↓	↓
W-8	↓	↓	↓	↓	↓	↓	↓
W-9	↓	↓	↓	↓	↓	↓	↓
W-10	↓	↓	↓	↓	↓	↓	↓
W-11	↓	↓	↓	↓	↓	↓	↓
W-12	↓	↓	↓	↓	↓	↓	↓
W-13	↓	↓	↓	↓	↓	↓	↓
W-14	↓	↓	↓	↓	↓	↓	↓
W-15	↓	↓	↓	↓	↓	↓	↓
W-16	↓	↓	↓	↓	↓	↓	↓
W-17	↓	↓	↓	↓	↓	↓	↓
TOTAL	0	-	234	0	0	162	45

TABLE A V-22

ADDITIONAL MANPOWER REQUIREMENTS FOR REFINERIES

WESTERN REGION CASE 4

MANPOWER (PERSONS) / REFINERY CASE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
W-1	0	-	13	0	0	9	2.5
W-2	↓	↓	↓	↓	↓	↓	↓
W-3	↓	↓	↓	↓	↓	↓	↓
W-4	↓	↓	↓	↓	↓	↓	↓
W-5	↓	↓	↓	↓	↓	↓	↓
W-6	↓	↓	↓	↓	↓	↓	↓
W-7	↓	↓	↓	↓	↓	↓	↓
W-8	↓	↓	↓	↓	↓	↓	↓
W-9	↓	↓	↓	↓	↓	↓	↓
W-10	↓	↓	↓	↓	↓	↓	↓
W-11	↓	↓	↓	↓	↓	↓	↓
W-12	↓	↓	↓	↓	↓	↓	↓
W-13	↓	↓	↓	↓	↓	↓	↓
W-14	↓	↓	↓	↓	↓	↓	↓
W-15	↓	↓	↓	↓	↓	↓	↓
W-16	↓	↓	↓	↓	↓	↓	↓
W-17	↓	↓	↓	↓	↓	↓	↓
TOTAL	0	-	234	0	0	162	45

TABLE A V-23

ADDITIONAL MANPOWER REQUIREMENTS FOR REFINERIES

WESTERN REGION CASE 5

MANPOWER (PERSONS) / REFINERY CASE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
W-1	0	13	-	0	0	9	2.5
W-2	↓	↓	↓	↓	↓	↓	↓
W-3	↓	↓	↓	↓	↓	↓	↓
W-4	↓	↓	↓	↓	↓	↓	↓
W-5	↓	↓	↓	↓	↓	↓	↓
W-6	↓	↓	↓	↓	↓	↓	↓
W-7	↓	↓	↓	↓	↓	↓	↓
W-8	↓	↓	↓	↓	↓	↓	↓
W-9	↓	↓	↓	↓	↓	↓	↓
W-10	↓	↓	↓	↓	↓	↓	↓
W-11	↓	↓	↓	↓	↓	↓	↓
W-12	↓	↓	↓	↓	↓	↓	↓
W-13	↓	↓	↓	↓	↓	↓	↓
W-14	↓	↓	↓	↓	↓	↓	↓
W-15	↓	↓	↓	↓	↓	↓	↓
W-16	↓	↓	↓	↓	↓	↓	↓
W-17	↓	↓	↓	↓	↓	↓	↓
TOTAL	0	234	-	0	0	162	45

TABLE A V-24

ADDITIONAL MANPOWER REQUIREMENTS FOR REFINERIES

WESTERN REGION **CASE** 6

MANPOWER (PERSONS) / REFINERY CASE	KERO	H-OIL		HYDROGEN PLANT	AMINE PLANT	SULFUR PLANT	SOUR WATER STRIPPER
		90%	66%				
W-1	0	13	-	0	0	9	2.5
W-2	↓	↓	↓	↓	↓	↓	↓
W-3	↓	↓	↓	↓	↓	↓	↓
W-4	↓	↓	↓	↓	↓	↓	↓
W-5	↓	↓	↓	↓	↓	↓	↓
W-6	↓	↓	↓	↓	↓	↓	↓
W-7	↓	↓	↓	↓	↓	↓	↓
W-8	↓	↓	↓	↓	↓	↓	↓
W-9	↓	↓	↓	↓	↓	↓	↓
W-10	↓	↓	↓	↓	↓	↓	↓
W-11	↓	↓	↓	↓	↓	↓	↓
W-12	↓	↓	↓	↓	↓	↓	↓
W-13	↓	↓	↓	↓	↓	↓	↓
W-14	↓	↓	↓	↓	↓	↓	↓
W-15	↓	↓	↓	↓	↓	↓	↓
W-16	↓	↓	↓	↓	↓	↓	↓
W-17	↓	↓	↓	↓	↓	↓	↓
TOTAL	0	234	-	0	0	162	45

POOR

QUALITY

ORIGINAL